S. Hrg. 100-428

CLEAN COAL TECHNOLOGY DEPLOYMENT ACT

HEARING

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDREDTH CONGRESS

FIRST SESSION

ON

S. 879

TO ENCOURAGE THE DEPLOYMENT OF CLEAN COAL TECHNOLOGIES SO AS TO ASSURE THE DEVELOPMENT OF ADDITIONAL ELECTRIC GENERATION AND INDUSTRIAL ENERGY CAPACITY

MAY 18, 1987

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CLEAN COAL TECHNOLOGY DEPLOYMENT ACT

MONDAY, MAY 18, 1987

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The committee met, pursuant to notice, at 2:05 p.m., in room SD-366, Dirksen Senate Office Building, Hon. J. Bennett Johnston, chairman, presiding.

OPENING STATEMENT OF HON. J. BENNETT JOHNSTON, A U.S. SENATOR FROM THE STATE OF LOUISIANA

The CHAIRMAN. Today, the full Committee is holding hearings on S. 879, Senator Byrd's Clean Coal Technology Deployment Act.

We have a full slate of witnesses, but I would like to direct my opening remarks to the representatives of the Department of Energy.

I believe that it is time for the administration to come forward and cooperate with this committee and with Congress in enacting a Clean Coal Technology Deployment program. It should be a program similar to the one that is envisioned in the Byrd bill.

An effective clean coal program will require more than provisions for appropriations for the administration to spend or not to spend as the OMB dictates.

An effective program will require statutory changes in the regulatory regime to encourage investment in cost effective clean coal technology. We should be making these changes, not just studying them.

Those who feel the actions attributed to acid rain are calling for action, by action they mean mandatory emissions reductions now. By action they mean the widespread of scrubbers, coal switching and forced retirement of plants.

If utilities are forced to make these actions now, there will be tremendous cost and economic dislocations.

Unfortunately, the result may not be any really significant reduction in the effects the actions are intended to mitigate. Clean coal technology is simply a much, much superior approach to this problem. The testimony on this is very clear.

But we cannot answer calls for action on acid rain with promises that the administration might do something someday after the studies are finished.

We need a program. We need a Congressional commitment to get on with the deployment of these technologies. We need to pass legislation like S. 879. And we need the administration's support.

The administration should come forward and work with us to get a bill passed.

[The text of S. 879 follows:]

X

100TH CONGRESS
1ST SESSION

S. 879

To encourage the deployment of clean coal technologies so as to assure the development of additional electric generation and industrial energy capacity.

IN THE SENATE OF THE UNITED STATES

MARCH 30, 1987

Mr. BYRD introduced the following bill; which was read twice and referred to the Committee on Energy and Natural Resources

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A BILL

To encourage the deployment of clean coal technologies so as to assure the development of additional electric generation and industrial energy capacity.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SHORT TITLE

SECTION 1. This Act may be cited as the "Clean Coal Technology Deployment Act".

FINDINGS AND PURPOSES

SEC. 2. (a) The Congress hereby finds and declares that—

(1) utilization of the vast coal resources of the United States in an environmentally acceptable and

cost effective manner is essential to our national security and will reduce growing dependence upon foreign sources of energy;

(2) there will be a need for additional electric generating capacity and other energy options in the United States before the turn of the century;

(3) widespread use of efficient and cost effective clean coal technologies will insure steady progress toward meeting our energy and environmental needs while preserving the livelihoods of Americans and the competitiveness of United States industry;

(4) the magnitude of the risks associated with the commercialization of these technologies are not compatible with normal electric utility rate-making procedures;

(5) establishment of the clean coal technology deployment program will better enable the private sector to assume those technological and financial risks that are attendant to the commercialization of emerging clean coal technologies;

(6) there is a need for coordinated development and application of regulatory, financial and other incentives, at the Federal and non-Federal level of government, to facilitate the widespread commercial application of clean coal technologies;

(7) coal utilization and environmental protection are mutually compatible and improved clean coal technology is the key to compatibility; and

(8) electrical energy needs of the future can best be met through the development of technologies capable of matching increments of demand to cost-effective and efficient amounts of capacity additions.

(b) The purpose of this Act is to encourage the commercial deployment of clean coal technologies by—

(1) establishing a program of Federal financial assistance for a limited number of commercial-sized clean coal technology projects;

(2) removing certain Federal regulatory impediments to the use by electric utilities of designated clean coal technologies; and

(3) providing coordination between State and Federal regulatory policies respecting utility use of designated clean coal technologies.

DEFINITIONS

SEC. 3. For purposes of this Act:

(1) The term "innovative clean coal technology" means any technology (including pre-combustion treatment of coal) at a new or existing facility which—

(A) will effect or facilitate a reduction in air emissions associated with the combustion or use of coal, and

(B) is not in widespread commercial use at the same scale in new or existing facilities in the United States.

(2) The term "federally assisted clean coal project" means any project for which the Secretary has approved financial assistance under section 4.

(3) The term "designated clean coal technology" means an innovative clean coal technology designated under section 5(a) as eligible for the regulatory treatment provided by sections 5 and 6(b).

(4) The term "clean coal project expenditure" means any cost or operating expense which is reasonably related to design, construction, or operation of—

(A) a new facility which utilizes a designated clean coal technology, or

(B) equipment installed to retrofit, repower or modernize an existing facility which will utilize a designated clean coal technology,

as determined under the regulations of the Secretary.

(5) The term "clean coal capital cost" means a clean coal project expenditure required (but for section 5(b)) to be booked to an asset account under 18 CFR, 101.

(6) The term "existing facility" means a facility in service prior to January 1, 1987.

(7) The term "new facility" means a facility other than an existing facility.

(8) The term "coal" means anthracite, bituminous or subbituminous coal, lignite, or any fuel derivative thereof.

(9) The term "air emission" means any emission of an air pollutant.

(10) The term "Secretary" means the Secretary of Energy.

(11) The term "Commission" means the Federal Energy Regulatory Commission.

(12) The term "Administrator" means the Administrator of the Environmental Protection Agency.

FINANCIAL ASSISTANCE FOR DEPLOYMENT OF CLEAN COAL TECHNOLOGIES

SEC. 4. (a)(1) The Secretary, pursuant to authority provided under provision of the Federal Nonnuclear Energy Research and Development Act of 1974 (Public Law 93-577), shall establish a Clean Coal Technology Deployment Assistance Program pursuant to which the Secretary shall provide financial assistance to such number of commercial-sized projects utilizing innovative clean coal technologies as the Secretary determines require Federal financial assistance to encourage their commercial deployment.

(2) The Secretary may provide assistance under this section to a project which utilizes an innovative clean coal

technology if the Secretary determines that the project will provide experience necessary at a commercial scale to reduce the technological, financial, and regulatory risks associated with such innovative clean coal technology.

(3) In determining whether to provide assistance to a project utilizing an innovative clean coal technology under this section, the Secretary shall consider the following criteria:

(A) The projected efficiency and cost effectiveness (including operation and capital costs) of the technology, in its widespread commercial application for the purpose of:

(i) energy production; and

(ii) reduction of air, water, and solid waste effluents.

(B) The extent to which the technology can be used at a large number of existing facilities, particularly those facilities which, because of size and location, contribute to interstate or international pollution.

(C) The extent to which the technology can be applied to existing facilities currently dependent on high sulfur coal.

(4) In determining whether to provide assistance under this section to a project located in a State, the Secretary shall consider the extent to which the State has adopted poli-

cies comparable to those applicable to the Commission under section 5.

(5) Assistance under this section shall be in the form of grants-in-aid of construction or operation or both. The Secretary may not provide assistance to a project under this section in an amount that exceeds 50 percent of clean coal project expenditures for such project, as estimated at the time of project selection. The provisos under the heading "Department of Energy, Clean Coal Technology," in title II of Public Law 99–190 (99 Stat. 1251) shall apply to assistance provided under this section.

(b) There are authorized to be appropriated not more than $350,000,000, for each fiscal year in the 10-fiscal-year period which begins after the date of enactment of this Act, to be available for obligation under subsection (a). If appropriations in a fiscal year are less than $350,000,000, the balance between $350,000,000 and the amount so appropriated is authorized to be appropriated in any subsequent fiscal year. Sums authorized to be appropriated under this subsection shall be in addition to the amounts available from the Clean Coal Technology Reserve established by Public Law 98–473.

REDUCING FEDERAL REGULATORY IMPEDIMENTS TO DEPLOYMENT OF CLEAN COAL TECHNOLOGY

SEC. 5. (a) The Secretary, by rule after consultation with the Administrator, shall designate one or more innovative clean coal technologies as eligible, in whole or part, for the regulatory treatment provided in subsections (b) and (c) of this section and in section 6(b). In designating any such technology, the Secretary shall take into account, to the extent such information is practically available, estimates of—

(1) the projected efficiency and cost effectiveness (including operating and capital costs) of the technology in its widespread commercial application for the purpose of:

(A) energy production; and

(B) reduction of air, water, and solid waste effluents;

(2) reliability; and

(3) efficiency of power production.

A designation of an innovative clean coal technology under this section shall state which of the provisions of subsections (b) and (c) apply to such technology, and whether section 6(b) applies.

(b) For purposes of determining whether the rates and charges of any public utility (as defined in section 201(e) of the Federal Power Act) are just and reasonable under sections 205 and 206(a) of such Act, the Commission shall apply the following criteria:

(1) Any clean coal project expenditure for design and engineering by such utility shall be allowed as an operating expense.

(2) Any clean coal capital cost incurred to retrofit, repower, or modernize an existing facility shall be included in rate base when incurred, except to the extent such cost is allowed as an operating expense under subparagraph (A).

(3) On application of the public utility, the Commission shall allow any clean coal capital cost (to the extent not allowed as an operating expense under subparagraph (A)) to be amortized over a 5-year period beginning with the calendar year in which—

(A) the facility, in the case of a new facility, or

(B) the retrofitted, repowered, or modernized equipment, in the case of an existing facility, is placed in service. A return shall be allowed on any unamortized amount in rate base.

(4) On application of such public utility, the Commission shall exercise its authority under the Federal Power Act to provide an incentive rate of return on any clean coal capital cost included in rate base.

(5) There is a rebuttable presumption that any clean coal project expenditure is prudent.

(c) The Commission may exempt any person from any provision of the Public Utility Holding Company Act and parts II and III of the Federal Power Act to the extent—

(1) either Act applies by reason of ownership or operation of any federally assisted clean coal project or any project using a designated clean coal technology; and

(2) the Commission determines such an exemption is necessary to permit such person to participate in such project.

COORDINATION WITH THE STATES

SEC. 6. (a) The Secretary and the Administrator each shall—

(1) meet directly with governors, State energy policymaking offices, State environmental regulatory agencies, the State regulatory authorities to explain the clean coal technology deployment program under this Act;

(2) encourage coordinated and expedited Federal and State permitting and siting procedures for projects using designated clean coal technologies;

(3) subject to the recommendations, if any, of the Administrator, encourage maximum flexibility of State implementation plans under section 110 of the Clean Air Act to accommodate projects using designated clean coal technologies; and

(4) encourage State energy policy agencies, the Governors and State regulatory authorities to adopt, at the State level, the regulatory incentives provided at the Federal level under section 5 in order to encourage the deployment of designated clean coal technologies.

(b) For purposes of determining whether in any proceeding before a State regulatory authority (as defined in section 3(18) of the Public Utility Regulatory Policies Act of 1978) the rates and charges of any State-regulated electric utility (as defined in section 3(17) of such Act) are just and reasonable, there is a rebuttable presumption that any clean coal project expenditure is prudent.

IMPLEMENTATION

SEC. 7. Not later than 6 months after the date of enactment of this Act, the Secretary shall prescribe regulations implementing this Act. As soon as practicable after funds appropriated in a fiscal year become available for obligation under section 4(b), the Secretary shall request proposals under section 4(a) for clean coal technology projects.

The **Chairman**. I would like to recognize my distinguished colleague from Kentucky, who has been a very strong supporter and leader in the whole area of clean coal technology.

Senator Ford.

STATEMENT OF HON. WENDELL H. FORD, A U.S. SENATOR FROM THE STATE OF KENTUCKY

Senator **Ford**. Thank you, Mr. Chairman. I thank you for the compliment.

I am very pleased with your position, as it has always been, and hopefully we can develop clean coal technologies as coal is our country's most abundant energy resource and currently more than half of the electricity generated is from coal, and that percentage has been increasing.

As the demand for electricity increases, so will the use of coal. In addition there is continuing concern regarding acid rain and further controls on emissions from coal burning power plants.

Clean coal technologies represent ways to use our vast coal resources in an efficient and environmentally acceptable manner. The increasing use of these technologies will contribute to both our energy and environmental policy objectives, and will retain the livelihoods of many Americans while increasing the competitiveness of United States industry.

As a co-sponsor of S. 879, the Clean Coal Technology Deployment Act, I am pleased to be here to discuss this important legislation. On April 2nd and April 9th, in the subcommittee on energy research and development, which I Chair, we heard testimony about some of the promising clean coal technologies.

We also heard testimony about some of the regulatory barriers that prevent deployment of these technologies.

S. 879, through a $350 million per year, 10 year cost sharing program, provides financial assistance for initial, high risk commercial scale operations.

This 10-year program will allow us to build upon the knowledge gained in the early years of our research to develop the best, most efficient and most environmentally sound technology possible.

There are great risks to electric utilities of committing to clean coal technologies. The current regulatory environment is biased toward low capital intensive, high fuel cost options.

In order to achieve a more widespread use of clean coal technologies, we must reduce the risk associated with proving these technologies.

It is hoped that once commercial scale demonstrations are operational and successful, there will be a wider acceptance of these technologies by utilities and their public service commissions.

To facilitate further the widespread use of clean coal technologies, S. 879 reduces certain Federal regulatory provisions and encourages capital investment. S. 879 also would pave the way for states to be supportive of clean coal deployment.

Clean coal has the potential to meet the increasing electric demand with a domestic resource, and to do so in an environmentally sound manner. We could deprive the nation of the benefits of these technologies by enacting an acid rain control legislation too early.

If we do this we may be forced to deploy our only available technology, scrubbers, at a very, very great cost. Our bill, S. 879, is to develop, demonstrate and deploy these clean coal technologies so they can become a part of the options available for burning coal more cleanly.

Mr. Chairman, I thank you for the opportunity to make this statement. I am looking forward to hearing from the variety of witnesses you have brought together today.

The CHAIRMAN. Thank you very much, Senator Ford. I am now going to put into the record statements from Senator McClure and Senator Nickles.

[The prepared statements of Senator McClure and Senator Nickles follow:]

OPENING STATEMENT
SENATOR JAMES A. McCLURE
RANKING MINORITY MEMBER
COMMITTEE ON ENERGY AND NATURAL RESOURCES
MAY 18, 1987 (2:00 P.M.)

S. 879, CLEAN COAL TECHNOLOGY DEPLOYMENT ACT

Good afternoon. May I express my appreciation to the Chairman for conducting this hearing on S. 879. This is a particularly appropriate time to be examining what is an appropriate Federal role in the deployment of clean coal technologies. In addition to the environmental benefits that are often cited, there are significant energy security benefits to be achieved from emerging clean coal technologies.

S. 879 can serve as the basis for achievement of these dual objectives and I look forward to working with the Chairman in reaching mutually agreeable legislation. I have also been assured that the Administration is prepared to work with us in this effort.

As the Chairman is aware, the objectives of the current DOE Clean Coal Technology program are very broad and not limited to acid rain control. The specific program objectives provide for the construction and operation of clean coal technology projects to demonstrate their feasibility for future commercial applications. But, importantly, the program objectives do not include the deployment of clean coal technologies, which is addressed by S. 879 and Administration proposals.

Last year I chaired full Committee hearings on the relationship between timetables being proposed for mitigation of acid rain and when results can be expected from the current DOE

PROGRAM. MY CONCERN WAS THE APPARENT DICHOTOMY BETWEEN WHEN NEW CLEAN COAL TECHNOLOGIES WILL BE AVAILABLE FOR DEPLOYMENT AND THE COMPLIANCE SCHEDULES IN PROPOSED ACID RAIN CONTROL LEGISLATION. I STILL HAVE THAT CONCERN.

IT IS CLEAR TO ME THAT IT IS IN THE NATIONAL INTEREST THAT ENERGY SECURITY CONCERNS BE APPROPRIATELY REFLECTED IN STRATEGIES FOR THE MITIGATION OF ACID RAIN. SIMILARLY, IT IS IN THE NATIONAL INTEREST THAT ENVIRONMENTAL CONCERNS BE REFLECTED IN STRATEGIES FOR THE DEPLOYMENT OF INNOVATIVE CLEAN COAL TECHNOLOGIES.

BUT, ABOVE ALL, IT WOULD BE INAPPROPRIATE FOR THE FEDERAL GOVERNMENT TO PROVIDE INCENTIVES THAT SIMPLY RESULT IN THE REPLICATION OF KNOWN, OFF-THE-SHELF TECHNOLOGIES SUCH AS SCRUBBERS. AND I WOULD OPPOSE SUCH LEGISLATION. WHILE IMMEDIATE, SHORT-TERM ENVIRONMENTAL BENEFITS MIGHT BE DERIVED, WE NEVERTHELESS WOULD DENY OUR COUNTRY THE ENERGY AND ENVIRONMENTAL BENEFITS THAN CAN BE ACHIEVED FROM EMERGING CLEAN COAL TECHNOLOGIES WITHIN A DECADE.

AS I STATED LAST YEAR, I HAVE FOUR BASIC CONCERNS. FIRST, WHAT IS THE APPROPRIATENESS OF USING FEDERAL FUNDS TO UNDERWRITE INDUSTRY EFFORTS TO COMPLY WITH STATE AND FEDERAL ENVIRONMENTAL LAWS. SECOND, IF WE MOVE TOO FAST WITH MORE STRINGENT ENVIRONMENTAL CONTROLS WILL THE EFFECT BE TO FREEZE AND DEPLOY KNOWN TECHNOLOGIES, SUCH AS SCRUBBERS, RATHER THAN DEPLOY NEW, INNOVATIVE CLEAN COAL TECHNOLOGIES. THIRD, WHAT IS GOING TO BE THE SOURCE OF THE FEDERAL FUNDS TO BE USED FOR DEPLOYMENT. AND, FOURTH, WHAT EFFECT IS A PROMISE OF FUTURE FEDERAL FUNDING GOING

TO HAVE ON PRIVATE INVESTMENTS THAT WOULD OTHERWISE OCCUR. THE PROMISE ALONE MAY VERY WELL STIFLE SUCH PRIVATE INVESTMENTS.

FINALLY, A MATTER RAISED BY S. 879 THAT WE DID NOT ADDRESS LAST YEAR CONCERNS THE POSSIBLE REGULATORY DISINCENTIVES THAT MAY ACCOMPANY DEPLOYMENT OF CLEAN COAL TECHNOLOGIES. SUCH REGULATORY CONCERNS ARE, IN PART, ADDRESSED BY S. 879. HOWEVER, I ALSO LOOK FORWARD TO RECEIPT OF THE RECOMMENDATIONS OF THE PRESIDENTIAL TASK FORCE ON REGULATORY RELIEF. MANY OF THE ISSUES THAT ARE BEING ADDRESSED BY THE TASK FORCE ARE GENERIC IN NATURE -- NOT LIMITED TO THE DEPLOYMENT OF EMERGING CLEAN COAL TECHNOLOGIES.

AS THE CHAIRMAN KNOWS, I HAVE SUPPORTED THE DOE CLEAN COAL TECHNOLOGY PROGRAM SINCE ITS INITIAL ADOPTION IN THE FY85 INTERIOR AND RELATED AGENCIES APPROPRIATIONS ACT, WHICH I AUTHORED.

AS WE CONSIDER S. 879 AND COMPANION LEGISLATION TO DEPLOY CLEAN COAL TECHNOLOGIES, WE NEED TO FULLY UNDERSTAND THE ISSUES I HAVE RAISED.

I LOOK FORWARD TO WORKING WITH YOU AND THE ADMINISTRATION AS WELL AS THE MAJORITY LEADER, SENATOR BYRD, TO FORMULATE LEGISLATION THAT ADDRESSES OUR MUTUAL CONCERNS.

STATEMENT OF SENATOR DON NICKLES
COMMITTEE ON ENERGY AND NATURAL RESOURCES
HEARING ON EXPANSION OF CLEAN COAL TECHNOLOGY PROGRAM
MAY 18, 1987

Mr. Chairman:

I appreciate the opportunity to make a few comments on the importance of national policies to expand the value of our Nation's fossil fuel resources. The Clean Coal Technology program promises to accelerate our ability to burn cleanly our Nation's most abundant fossil fuel. At the same time, however, we must not abandon our most clean burning fuel resource--natural gas--or our most widely used fuel--petroleum. Yet this is precisely what the federal government is doing when the DOE sends up budget requests totaling $350 million for Clean Coal Technology, but cuts an already meager oil and gas research budget of $34 million appropriated for FY 1987 to $14 million proposed for FY 1988.

In view of the finding of the Department of Energy's recent Report on the Energy Security of the United States, it is astounding that the only significant new proposals made by the Department are to ask for a total of $2.5 billion for Clean Coal Technology over the next five years and to propose a superconducting supercollider that will cost $5.7 billion. I look forward to the opportunity on Wednesday to discuss with the Deputy Secretary the Department's rationale for essentially ignoring the findings of its recent Report on the Energy Security of the United States.

The **Chairman**. We are pleased to welcome the Hon. J. Allen Wampler, Assistant Secretary for the Fossil Energy Research and Development Programs from the Department of Energy, who has worked very closely with us on these matters, even though we have not gotten the whole department to go as far and as fast as we would like.

With him is J. Craig Potter, assistant administrator for air and radiation at EPA. Excuse me, Mr. Potter is to come later. Mr. Wampler, you might introduce those who accompany you and please proceed.

STATEMENT OF J. ALLEN WAMPLER, ASSISTANT SECRETARY FOR FOSSIL ENERGY, DEPARTMENT OF ENERGY, ACCOMPANIED BY DONALD BAUER, PRINCIPAL DEPUTY ASSISTANT SECRETARY FOR FOSSIL ENERGY; AND JACK SIEGEL, DEPUTY ASSISTANT SECRETARY FOR COAL TECHNOLOGY

Mr. **Wampler**. Thank you, Mr. Chairman. My opening statement will be brief and will summarize the prepared testimony that I have submitted for the record.

I have with me today Mr. Donald Bauer, my Principal Deputy to my left, Mr. Jack Siegel to my right, the Deputy Assistant Secretary for Coal Technology.

I open my written testimony, Mr. Chairman, with the statement that we have a unique opportunity in front of us. I believe that is true from two perspectives.

One is the nature of the technology itself. The research and development conducted by this nation over the last decade has in fact brought us to the point where we have the opportunity to resolve the conflict between coal use and environmental protection. We can have both.

The second, Mr. Chairman, we have the opportunity to forge a bipartisan approach to carrying out the clean coal program. The President's initiative on March 18th of this year started us along that path.

Senator Byrd's Clean Coal Deployment bill, S. 879, advances us along the same fundamental course.

That gives us an opportunity to fine tune the clean coal program in concert with Congress, rather than remaining at cross purposes.

The President is committed to a leadership role in carrying out this program. I recognize that you, Mr. Chairman and other Members of this committee, are committed to the same objectives.

So we in the Department of Energy are prepared to work with this committee and other Members of Congress to fashion a workable approach that returns the most benefits to the coal industry and to this nation as a whole.

Many things we can do administratively, and those are underway. Many things may need legislative action, particularly once we have seen the recommendations coming out of the Vice President's Task Force on Regulatory Relief. But we enter this process moving toward the same goal, and I think it bodes well for this program.

I have addressed in my formal statement several similarities between the President's program as directed in his March 18th announcement, and the program proposed in S. 879.

In the interests of time I will not repeat what is in the statement, except to make two points.

First, we continue to support a $2.5 billion five year effort, rather than the larger amount and longer duration program proposed in S. 879.

One reason is obviously budget driven. But we are also concerned about developing an expanded suite of technologies in a time frame that is sufficiently compressed to meet what I would term a window of opportunity opening in the mid-1990s.

At that point, Mr. Chairman, more than half the coal-fired boilers in this country will be more than 25 years old. Utilities will be facing some fundamental decisions about retiring them or keeping them in operation.

At the same time electric demand will be growing, and with it the need for additional power generating capacity.

Some have looked at the clean coal program as solely an environmental program, and in large part it is. But given the potential of some of the technologies from this program to give utilities not only emission reductions, but life extensions and increased generating capacity at existing sites, it is clear that the benefits of clean coal technology can also meet other pressing national concerns.

We also cannot view the clean coal program as a substitute for an in-depth study of the causes and effects of acid rain. We still need that information. And the National Acid Precipitation Assessment Program is working toward a 1990 deadline of providing this data.

At that time, if the analyses show that we need accelerated emission reductions, it is important to have as broad a menu of control options available as possible. Therefore we see a 5-year time frame to get these first of a kind demonstration projects up and running as very important.

The second point I would make, Mr. Chairman, deals with the deployment issue. One of the factors that will determine the success of the clean coal initiative is certainly how emerging technologies will be replicated and deployed once they are demonstrated.

The President has recognized that. He has asked the Vice President to examine disincentives that can stand in the way of full commercial use of these new technologies.

Senator Byrd also recognizes that and has included a series of regulatory measures in S. 879 to stimulate deployment.

Some of these provisions, as I mentioned, might be candidates for implementation through the administrative process. Others might be implemented or at least reinforced through legislative actions.

I believe the important point, Mr. Chairman, is that both the administration and Congress have recognized that demonstration projects alone may not ensure commercial deployment for all successful technologies.

We are prepared to work with you in a constructive fashion to develop the best approach for using market forces to deploy these technologies. We believe that it is far preferable to remove regulatory barriers than to enact a very costly emissions control program that would lock us into today's limited technologies.

That is why we are pleased to be here today, Mr. Chairman, and to answer any detailed questions you or Members of the Committee may have. Thank you very much.

[The prepared statement of Mr. Wampler follows:]

Testimony of

J. ALLEN WAMPLER
Assistant Secretary for Fossil Energy
U.S. Department of Energy
to the
Committee on Energy and Natural Resources
U.S. SENATE

May 18, 1987

Mr. Chairman and Members of the Committee:

I am pleased to have this opportunity to describe the Administration's efforts to implement a national Clean Coal Technology demonstration program in comparison with initiatives proposed by Members of Congress.

We have a unique opportunity in front of us, Mr. Chairman. Research and development over the last decade has given us the tools to resolve the conflict between coal use and environmental protection. Properly developed, demonstrated and deployed, emerging clean coal technologies offer not only improved environmental performance and better economics but also, in many cases, enhanced efficiencies and the potential to boost both the lifetime and power output of today's older coal-burning facilities.

President Reagan's March 18, 1987, commitment to expand the nation's Clean Coal Technology program is an important step toward improving America's energy security through the use of our most abundant fossil fuel resource -- coal -- in an environmentally safe, cost-effective manner. "The Clean Coal Technology Deployment Act" (S.879) introduced on March 30, 1987, and the bill's counterpart in the House of Representatives, H.R.1995, are similar attempts to advance this nation along the same course.

The Administration agrees with the sponsors of these bills on the national significance of the innovative clean coal technology program, both to environmental quality and energy security. The Administration is already implementing many of the efforts outlined in these bills administratively and is examining what additional administrative and regulatory actions can be taken to further advance the demonstration and deployment of clean coal technologies.

The President is committed to an aggressive, leadership role in moving innovative clean coal technologies over the commercial threshold. This has been evidenced by the Administration's request for the Congress to provide the full amount of the $2.5 billion in federal funding in FY 1988 appropriations and advance appropriations for FY 1989, 1990, 1991 and 1992.

Although Congress will continue to exercise its oversight and budgeting authorities in shaping the future course of the clean coal program, appropriating the full amount of funding will give industrial sponsors confidence that the federal share of funds will be available when they are asked to commit their share of project costs.

The Benefits of Clean Coal Technology

The President's March 18 initiative addresses the serious issue of acid rain, a major concern of both the U.S. and its northern neighbor Canada. The innovative clean coal technology program, however, will do much more than simply address a pressing international environmental problem. The commercially-ready technologies that emerge from this effort will:

- o Greatly enhance U.S. technological leadership and international competitiveness;
- o Benefit both Eastern and Western states by making available more cost-effective, fuel-flexible power systems capable of using the full spectrum of U.S. coals;
- o Improve international trade by providing a more attractive, marketable "package" of both coal and the advanced technology to use it and by reducing the cost of energy-intensive U.S. goods;

- Help ensure that the U.S. enters the 21st Century with a broad array of sophisticated, cleaner, and more economical coal-based energy technologies, rather than being limited to the more costly, less effective environmental control options available today; and

- Enhance the long-term energy security of the U.S.

For these reasons, implementing an expanded clean coal technology program is just as important for safeguarding this nation's future energy security and economic vitality as it is for safeguarding our environment.

A Comparison of the President's March 18 Initiative and S.879

On March 18, 1987, the President proposed a 5-year, $2.5 billion (federal share), cost-shared effort to demonstrate innovative clean coal technologies at commercial or near-commercial scale. The program would be fashioned, as fully as practicable, from the recommendations contained in the 1986 Report of the Special Envoys on Acid Rain. In implementing the program, the Secretary of Energy will receive advice from an Innovative Control Technology Advisory Panel currently being established as part of the President's directives.

The President also directed the Vice President's Task Force on Regulatory Relief to undertake a 6-month review of federal and state economic and regulatory programs to identify opportunities for addressing environmental concerns under existing laws. The Task Force will examine incentives and disincentives to the deployment of new emission control technologies and recommend changes to existing regulations that now inhibit that deployment.

S.879, by comparison, proposes a $3.5 billion, 10-year financial assistance program coupled with several regulatory incentives designed to enhance the commercial deployment of new coal technologies, particularly in regulated markets such as the utility market.

There is a substantial degree of common ground between the President's March 18 Clean Coal Technology initiative and the proposed program offered in S.879. Both recognize that an effective clean coal effort should encompass:

- a cost-sharing effort to demonstrate the commercial potential of innovative, emerging technologies, particularly in markets where the regulatory structure increases the adversity to risk-taking, and
- a deployment strategy in which incentives are fashioned from the removal of regulatory barriers rather than a potentially premature, very costly and economically disruptive program of added environmental controls.

The major distinctions between the President's March 18th initiative and S.879 are:

- S.879 provides $3.5 billion in increments of $350 million annually over a minimum of 10 years and appropriations would continue indefinitely until all funds had been provided. The Administration's program establishes a set period, 1988 through 1992, for the appropriation of $2.5 billion, targeting its resources for maximum benefit in time for key utility decisionmaking in the mid-1990s;
- Financial assistance in S.879 would be in the form of construction and operation grants. The Administration's program provides for cost-shared cooperative agreements which provides much stronger assurances of recipient performance in line with program objectives;
- To promote the deployment of new clean coal technologies, S.879 proposes several regulatory actions under the jurisdiction of the Federal Energy Regulatory Commission as well as several provisions that pertain to state regulatory proceedings; the President, in his March 18 announcement, directed that similar regulatory measures be reviewed by a Vice Presidential task force.

Other similarities and distinctions are that:

- Both S.879 and the President's program would cost-share with industry the demonstration of innovative pollution control technologies applicable to existing, coal burning facilities, although such demonstrations could be conducted on either new or existing plants;

- o Both would base the selection of projects on evaluation criteria similar to those proposed by the Special Envoys on Acid Rain although only the President's program explicity incorporates the Envoys' recommendations;
- o Both S.879 and the Administration would encourage States to be actively involved in clean coal technology efforts;
- o S.879 would support technologies capable of reducing any type of pollution from coal burning facilities in any location while the Administration, in adhering as closely as possible to the recommendations of the Special Envoys on Acid Rain, would emphasize (but not limit itself to) a reduction of sulfur dioxide and nitrogen oxide pollution;
- o Many of the factors considered in evaluating and selecting projects, i.e., projected commercial efficiency and effectiveness, market penetration potential, applicability of technology to high sulfur coal burners, etc., are common to both proposals;
- o Both proposals limit federal financing to 50 percent during any phase of the project with limits on government funding of cost overruns, although the Administration would propose to recover the federal contribution by negotiating recoupment provisions;

Rationale for the President's $2.5 Billion, 5-Year Demonstration Program

The Administration believes that the financial assistance limits of $2.5 billion over a five-year period, as pledged by the President on March 18, are preferable to the proposed $3.5 billion, 10-year program in S.879. We believe that providing $500 million per year for the federal share of clean coal projects is necessary to concentrate the demonstration of new technologies in a manner that meets a "window" of opportunity that will open for these systems in the mid 1990s.

By the middle of the next decade, utilities will be increasingly confronted by the dual problem of an aging boiler population and the need for increasing their power generating capacity. More than half of all coal-fired boilers will be 25 years old or older by the mid-1990s. In the eastern U.S. alone, there are 410 units of coal-fired utility capacity of 100 megawatts or larger that were placed in service from 1955 to 1975 and which do not have post-combustion SO2 control devices. Utility decisionmakers will soon have to make some fundamental choices about many of these units -- including whether to retire or refurbish them.

At the same time, demand for electricity will be growing and today's reserve margins declining. Estimates for increasing power demand vary typically between two and three percent, but even with the more conservative, two-percent growth rate, the U.S. could require as much as 100,000 megawatts of additional capacity by the end of the next decade.

If technologies such as combined cycle gasification or fluidized bed combustion (either atmospheric or pressurized) are successfully demonstrated at commercial scale between now and the early 1990s, utilities may be able to resolve the two-fold problem of modernizing aging plants and increasing power demand with a single answer.

Repowering a conventional steam-cycle plant with pressurized fluidized bed combustion, for example, can increase the plant's power output by 30 to 50 percent. Installing gasification-combined cycle as a replacement for the conventional boiler can boost output by as much as 150 percent. This increase in power output from an existing facility could defer the need to build a new increment of baseload facilities. The repowered plant would also be capable of reducing sulfur emissions by as much as 99 percent at a cost of as little as $80 to $250 per ton of SO_2 removed (compared to the addition of a scrubber which could cost $500 per ton or more). Nitrogen oxide emissions would also be lowered to well below present federal standards for new units.

If utilities are to have the performance data available in time to take advantage of the clean coal technology repowering option, demonstration facilities must be constructed and in operation by the early 1990s.

These inherent economic and performance advantages of clean coal repowering options will be beneficial both to the eastern and western regions of the U.S. -- particularly in areas where power demand is expected to continue to rise. In carrying out the President's March 18th initiative, we believe it is important not to exclude consideration of promising clean coal options that may be demonstrated outside the eastern region of the U.S. As long as such projects demonstrate a relevant technology, i.e., a technology applicable to existing, high-sulfur coal burning plants, they should be eligible for clean coal financial assistance. In addition, many of the retrofit technologies -- i.e., the limestone injection multistage burner and several advanced combustor concepts -- while not able to attain the NSPS 90 percent sulfur reduction standards for new, high-sulfur coal burning plants, may be able to attain the 70 percent removal standards for plants using low-sulfur subbituminous coal or lignite.

Therefore, we believe that a clean coal technology demonstration program, adhering to the Special Envoys' recommendations, will have major benefits for the nation as a whole, both East and West, and for both the taxpayer and the ratepayer.

Another factor regarding influencing the 5-year timeframe of the President's program is that the final report of the National Acid Precipitation Assessment Program is scheduled to be available in 1990. By that time, policymakers should have much better information to decide if additional environmental controls are warranted. If the evidence shows the need for an accelerated reduction in sulfur and nitrogen pollutants from coal plants from existing sources, especially pre-NSPS plants, it is important to have an expanded menu of low cost per ton retrofit control and repowering options available.

Therefore, the early to mid-1990s is a critical time for decisionmaking, both in terms of continuing to provide reliable electrical service and in meeting national environmental objectives. The Administration believes it is important, therefore, to concentrate the clean coal demonstration effort over the next 5 years rather than extending it over 10 years as called for in S.879.

S.879 currently envisions grants in aid for clean coal projects. The Administration adopted the cost-shared "cooperative agreement" as the procurement vehicle for the initial round of Clean Coal projects, and such a contractual instrument is one of those being considered for future Clean Coal projects as well. A cooperative agreement often requires a considerable degree of negotiation between the government and the proposer. Such negotiations are necessary to ensure that federal funds are expended only on allowable project costs and that patent rights, licensing arrangements and other project details are properly executed in a manner that is in the best interests of both the government and the project sponsors.

The Department also believes a repayment provision for up to the Government's share of the financial assistance remains appropriate. Repayment, in the event the demonstration project or technology becomes a commercial success, provides a fair return to the taxpayer who has shared the risks of the original project.

We recognize, however, that repayment provisions must be sufficiently flexible so as not to dampen the interest of prospective participants in the program. We also recognize that repayment provisions cannot be uniformly administered for different market sectors and must consider, for example, the regulated business environment of electric utilities.

Conclusion

While there are many positive parallel approaches between S.879 and the President's decision on March 18, the Administration believes that its program implementing the recommendations of the Special Envoys on Acid Rain, has the greater potential to achieve the important goals that the two programs share. The March 18 decision also fulfills assurances given by our Government to the Government of Canada. The Administration feels strongly that any actions taken to expand and advance the nation's Clean Coal Technology demonstration program should be fully supportive of and consistent with those assurances.

The President's innovative clean coal technology initiative offers the means for the U.S. to achieve the full potential of its most abundant domestic resource without endangering its environment -- a goal shared by S.879. In accord with the President's initiative, the Administration is prepared to carry out an innovative clean coal technology program that:

1) is consistent with the Special Envoys Report on Acid Rain;

2) provides necessary financial assistance in the form of cost-sharing with industry for innovative projects that are in the national interest while ensuring against undue subsidies;

3) is conducted within a timeframe consistent with expected utility decisionmaking and/or the revision of national policy regarding environmental emission standards; and

4) offers regulatory incentives that allows new clean coal technologies to be considered in utility and other market-driven decisionmaking.

This completes my formal statement, Mr. Chairman.

The **Chairman**. Thank you very much, Mr. Wampler. I am very interested in drawing out some of the ways you believe that Senator Byrd's bill might be changed and modified so as to have the best chance of getting the Department's support.

Let me start by discussing the criteria for project selection. The President said he wants to follow the special envoys 'recommendations, and Senator Byrd parallels many of these same provisions.

It would be helpful to the Committee if you would tell us whether the criteria in S. 879 will permit you to carry out the special envoys 'recommendations.

Mr. **Wampler**. We in the Department have certainly carefully examined the provisions of S. 879 dealing with the criteria you mention. As as you say they are generally along the lines of the special envoys' report. The criteria, however, that are outlined in the special envoys 'report are not precise procurement related criteria.

One of the tasks that the Department has in front of us is to take the special envoys 'recommendations and translate those recommendations into very specific evaluation criteria.

Consequently we feel that we should caution against specifying actual selection criteria in legislation. It is important, however, that we have guidelines and if it is important to have guidelines like this in the bill, I believe the Department would prefer to have these couched in terms of factors.

Those factors are ones that could be used by the Secretary in formulating evaluation criteria.

The **Chairman**. Now if you were drafting the legislation, if you were drafting the criteria, what would those factors be? How would you describe them?

Mr. **Wampler**. Let me answer that by giving you some thoughts on what we see as the most important considerations in putting together our procurement document.

First would be the extent to which technology will expand the menu of air pollution control options available to existing coal fired power plants.

The second would be the extent to which the demonstration plant and/or the commercialized version of that demonstration plant and of the technology can contribute to reductions in transboundary air pollution.

In considering this factor, Mr. Chairman, I pick up on some of the specific recommendations of the envoys. For example, I would consider the efficiency of SO_x and/or NO_x removal and the cost effectiveness of the technology in terms of dollars per ton of SO_2 and NO_x emissions reduced, and then those retrofit repowering technologies that are applicable to the largest number of existing sources that contribute to trans-boundary air pollution.

I consider all of these factors to be consistent, Mr. Chairman, with the envoys' recommendations.

The **Chairman**. Senator Byrd's bill also has other criteria specified.

The degree to which the technology reduces non-air quality pollution from coal combustion, potential for the technology to reduce the cost of producing additional electrical power, and the extent to which a state has adopted favorable regulatory practices.

What are your views on these criteria?

Mr. **Wampler**. I do not think that the Department would have any problem at all with adapting these provisions as part of an overall project evaluation criteria.

I might add, Mr. Chairman, as we look for ways to encourage state utility commissions to adopt rate-setting or other regulatory provisions to stimulate the deployment of clean coal technologies, that using the state's actions as a weighting factor in project selection process may be a very useful approach that would not intrude on state's regulatory authorities.

The **Chairman**. On page 7 of your formal statement, you point out that several of the technologies that you see coming out of the clean coal program will benefit both the west and the east.

Do you envision western projects in your demonstration program, or would you exclude those projects?

Mr. **Wampler**. We believe it is very important in developing criteria, Mr. Chairman, not to exclude western projects.

As long as the projects demonstrate a relevant technology, that is a technology that in its commercial form could be used in existing high sulfur coal burning plants, they should be eligible candidates for clean coal financial assistance.

A classic example, Mr. Chairman, would be a plant like the Cool Water Gasification Combined Cycle demonstration facility in California. That facility demonstrates a technology applicable to eastern high sulfur coal facilities, but just happens to be sited in another region of the nation.

We would not want to rule out a project like that, simply because it is not sited east of the Mississippi River. We do not consider the clean coal program as an east versus west program.

Many of the technologies coming out of this effort will be just as useful in burning high ash western coal as they are for high sulfur eastern coal.

Another important point is the inherent fuel flexibility of virtually all the clean coal concepts. That is a key advantage of this program, Mr. Chairman.

The **Chairman**. I have seen that cool water plant, and I hope it does have the promise to be replicated around the country.

I know many of the technologies and the engineering things that are done there are done on a one time basis for demonstration purposes and could be streamlined as it would be replicated. And I hope that way you can get the costs down for future plants of that nature.

S. 879 currently envisions grants-in-aid for clean coal projects. You have used a cost-shared cooperative agreement in clean coal round 1. Do you see any flexibility in other types of financial assistance approaches?

Mr. **Wampler**. Well, speaking for the Department, Mr. Chairman, which as you mention is currently negotiating some very, very complex clean coal agreements in round number 1, I believe it is very important that we keep an open mind about the types of financial assistance that we have in future rounds.

You are correct that we have used only the cooperative agreement as a procurement vehicle for the first round, but I am looking at other approaches. I am not convinced, Mr. Chairman, for example, that some type of grant might not be appropriate for some projects.

For example, projects that are less than $1 million with shorter durations entailing less technical or financial risk may be candidates for a grant. I think that it is our purpose to see the broadest spectrum of participation in this program.

For example, I would like to see small businesses play a greater role. They frequently simply do not have the resources to develop the detailed pre-award information required for a cooperative agreement.

So I have not closed the door to any financial approach, Mr. Chairman, for future rounds.

The CHAIRMAN. Senator Ford?

Senator FORD. Thank you, Mr. Chairman. Before we leave the financial assistance portion of the bill, Mr. Secretary, let me turn to a subject that we have discussed several times before, and that is the issue of repayment.

To say that that provision has been controversial is probably an understatement. Are you having any second thoughts about repayment requirements?

Mr. WAMPLER. Senator Ford, we still think that a repayment provision for up to the government's share of the financial assistance remains appropriate.

However, as I said in my formal statement, we recognize that repayment should be fashioned in a way that does not dampen the interests of prospective participants. And I am particularly concerned as I know you are about the participation of this nation's regulated utilities.

I would like to see the secretary have the authority to exempt regulated utilities from recoupment requirements having to do with the extended operations of a demonstration plant. In other words, past the time that the Federal program has ended.

I also think that it is wise that we consider the use of provisions other than revenue-generating sources. Cost caps, royalties for use of the technology of U.S. firms, for example, may be acceptable alternatives to recoupment.

Again, I think we want to incorporate as much flexibility as possible into this program and not let recoupment become a deterrent.

Senator FORD. Mr. Secretary, let us turn our thoughts now to the regulatory portion of S. 879.

You did not say very much about these provisions in your formal statement. Why was that?

Mr. WAMPLER. Senator, I do not think we have complete unanimity within the administration on this issue at the present time. I think there are several reasons for that.

One, the Vice President's Regulatory Relief task force has just gotten underway, and are looking into many of the same issues and possible fixes raised in S. 879.

They are trying to place those specific issues in the context of other possible disincentives just beyond economic obstacles. So it is a little bit early for us to give you a complete comprehensive review of possible regulatory actions.

Secondly, we feel that there are some ways that we can accomplish some of these regulatory approaches administratively. In fact, we may already have some precedent, for example, in previous actions that have been taken by FERC.

Others might require specific legislation, such as is included in S. 879. I think these are the primary reasons why I did not address the issue more thoroughly in my prepared statement, Senator Ford.

Senator **Ford**. Mr. Secretary, I am interested in what you just said about FERC already having precedent for some of the regulatory actions.

Can you be more specific on that?

Mr. **Wampler**. Certainly, Senator. For example, S. 879 would direct FERC to include the capital costs of clean coal projects as they are incurred in determining a just and reasonable rate for the wholesale marketing of electricity.

FERC has already established the precedent for including 100 percent of the costs of construction for pollution control devices into the rate base as the costs are incurred.

The precedent also exists for allowing 50 percent of other costs. It might not be unreasonable, therefore, for FERC to permit 100 percent of all capital costs for clean coal projects under their jurisdiction to be included in the rate base as the costs are incurred.

Senator **Ford**. Mr. Secretary, what about the provisions in S. 879 for an incentive rate of return?

Mr. **Wampler**. Senator, I do not think the Department would have a problem with that either.

Again, we believe there is precedent at FERC for offering an incentive rate of return for capital costs included in the rate base for risky projects. And this provision could very possibly be extended to clean coal projects under their jurisdiction.

If that could be done, it would provide investors with an added economic return. Unlike some of the other provisions, it could be applied on a case by case basis and that would allow risk-reward assessment to be done for each particular investment.

Senator **Ford**. I am going to take it that you, having no objections to implementing some type of incentive at the Federal level, either by statute or administratively.

But I guess what concerns a lot of people in this business is what happens at the state level, in the state public utility commissions or public service commissions, however they are referred to in their individual states.

You have indicated that you would like to use the financial assistance program as a "carrot" to the states to adopt favorable regulatory provisions. So I would assume that you would see state policies as being a possible obstacle.

Mr. **Wampler**. In many cases, Senator Ford, I think that is correct. States, as you know, govern the retail sale of electricity to the consumer.

We share the concern of many clean coal developers that increasingly state regulatory commissions are refusing to allow utilities to recover capital, or to earn profits when hindsight considers those investments to be imprudent.

What happens is that this creates a bias toward low capital investment projects, high fuel cost alternatives. To give you a hypothetical example of that, the prudency issue could have a major impact on the utility's adoption of a technology such as integrated gas fired combined cycle system, regardless of how well it is demonstrated.

Under state policy that encourages risk aversion, discourages capital investments, a utility might install a gas fired combined cycle system, which is a low risk activity, but would very likely resist subsequent addition of a coal gasifier, even though economics might dictate the switch to coal in the future.

Coal gasification is a higher risk, more capital intensive installation, and thus much more susceptible to a retrospective finding of imprudency by a state utility commission.

Senator **Ford**. Mr. Chairman, my 10 minutes are almost up. I just have two more questions.

What can the Federal government do? Senator Byrd has offered some suggestions in his bill.

Mr. **Wampler**. I am certainly familiar with those provisions and I think some offer some very constructive approaches for dealing with this issue.

I would like to emphasize to this committee, however, that when we examine each of these approaches we certainly should remain cognizant of state authorities in this area. We do not want to place the Federal government in the position of overriding these authorities.

In that context I would hope that one of the findings coming out of the Vice President's task force will be some way that the administration could urge state regulatory authorities to consider the national benefits of clean coal technologies in setting rates, particularly benefits such as environmental quality, the competitiveness of U.S. industry, and national security.

I would endorse the provisions in S. 879 that would encourage the Secretary or someone representing the Secretary to meet directly with state officials to explain the national and regional benefits of an aggressive clean coal deployment strategy at the state level.

I think we need better coordination with states in expediting Federal and state permitting the siting procedures, for projects that are going to be using clean coal technologies.

I think it may be possible to encourage maximum flexibility within state implementation plans, for example, under section 110 of the Clean Air Act, and to accommodate projects using designated clean coal technologies.

Senator **Ford**. Mr. Secretary, this will be my last question, but we were talking earlier about east and west projects and so forth.

But high sulfur coals from the eastern section of the United States, such as Kentucky, West Virginia, Ohio, can be successfully utilized, I think, in coal gasification, such as the Cool Water plant which you mentioned earlier for electricity production. Can they not?

Mr. **Wampler**. Yes, they can.

Senator **Ford**. Do we need further tests or demonstrations from these eastern coals before gasification with them will be considered commercially viable and accepted by the electric utilities, particularly the utilities thinking about new investment in coal fired power plants?

Where and how could this testing and demonstration be done?

Mr. **Wampler**. Well, I think specifically the project at Cool Water has done, I am informed, a limited amount of testing of high sulfur coal.

So that particular technology works equally well on both types of coal. The high sulfur coals can and are successfully being utilized to generate electricity. Cool Water is an example of that.

The objective of our program is to demonstrate technologies applicable to high sulfur coal burning plants. I think that, back to the answer I gave you a moment ago on east versus west, I think that any project that demonstrates it is relevant to the burning of high sulfur coal would be eligible under the clean coal demonstration criteria.

The **Chairman**. Senator Domenici?

Senator **Domenici**. Thank you. Mr. Secretary, let me just ask a question about a couple of differences.

I think one thing the administration has in its proposal that I think is rather important, that is not in Senator Byrd's bill, is the establishment of an advisory board, including state representatives and a Canadian representative, not by way of making final decisions but by way of being advisory.

Can you explain to us why you think that is important, and if you think it is a significant part of the administration's proposal?

Mr. **Wampler**. Yes, I think it is extremely important. It is not only important to provide a panel to give advice to the Secretary, but it is also important to make sure that that advisory panel covers a broad spectrum of interests.

We are currently contemplating the establishment of that panel at the Department, we contemplate the membership of various Federal agencies, including the Department of Energy of course, the State Department, Development of the Interior, Commerce, as well as EPA, and OMB.

We contemplate also Canadian membership on the panel, and we contemplate a large number of state memberships. Not only from states that produce coal, but states that use coal.

The largest group contemplated now would be the public group, consisting of a membership of electric utilities, environmental groups, boiler owners, union organizations, that kind of representation. So I think it is very important that we keep this panel in a broad spectrum and I think this panel is a highly important ingredient to this whole process.

Senator **Domenici**. Well, Mr. Secretary, I personally think that the chairman of this committee is to be commended for calling these hearings and calling them quickly.

And whether I agree in every detail with Senator Byrd's proposal or the administration's proposal, I think it is imperative that we handle it in a manner wherein we have authorized a clean coal program and had an opportunity to debate it, discuss it as we are here, in contrast to building a Clean Coal Technology Program around an appropriation process with no authorization.

I assume that the administration supports the approach of Congress in passing a piece of authorizing legislation that would later be implemented by the appropriation process. Is that correct?

Mr. WAMPLER. Well, the Department, either this afternoon or tomorrow, will be sending its non-nuclear authorization bill up.

It has been approved and is on its way up. Clean coal technology is contained in a one sentence authorization part of that bill, as I understand.

Senator DOMENICI. The department is sending that up, you say?

Mr. WAMPLER. This afternoon or tomorrow morning.

Senator FORD. It is one sentence?

Mr. WAMPLER. One or two sentences, talking about a $2.5 billion program. Yes.

The CHAIRMAN. Does it say we hereby endorse the Byrd program? [Laughter.]

Senator FORD. Is it just appropriations? No regulatory provisions?

Mr. WAMPLER. It is just authorization, not appropriations.

Senator DOMENICI. I take it, Mr. Wampler, indeed you do believe that, if we work together, we can build a program that the administration can support, that is built around the Byrd bill. Do I hear you right?

Mr. WAMPLER. Yes, I think we can build an approach that we can all support. I see a very unusual opportunity in the clean coal program.

We have had meetings with several of your staffs, and will continue to have those kinds of meetings in an effort to forge a truly bipartisan approach to this, and try to get the support of the administration in that effort.

Senator DOMENICI. Well, I have one area that I have an interest in that is not included in either the Byrd proposal nor have I seen it recommended officially by the department.

But it does seem to me that if we are going to spend large amounts of money over 5 or 10 years in this area, that there is a slight risk that we will lock in technology rather than continue the scientific exploration of coal, its chemistry, and those kinds of things that would permit us to really know everything there is to be known about coal.

I think we ought to seriously consider a research program, it does not have to be large, but a small research program that goes to the essence of coal, that is conducted perhaps by the national laboratories in consortium with the private sector, where they would continue work on the chemistry of coal so that we do not lock ourselves into technology only, or even freeze technology, but continue down that knowledge path.

I have not had an opportunity yet to discuss it with you personally. I have discussed it with the secretary, just by way of a general meeting. Would you care to address that at this point, or would you prefer to explore it and let us know later?

Mr. WAMPLER. Well, I would certainly like to explore it, but let me say basically that I agree that continuing and perhaps even supplementing our long term R&D, since we will be engaged with Congress 'approval in this large term effort, is going to be very important.

So I would welcome the opportunity to discuss that with you or your staff, Senator.

Senator DOMENICI. I thank you very much. I have no further questions.

The CHAIRMAN. Senator Ford, do you have further questions?

Senator FORD. No.

The CHAIRMAN. Thank you very much, Mr. Wampler. You have been very helpful to the Committee.

Next we would like to welcome J. Craig Potter, who is assistant administrator for air and radiation at EPA.

STATEMENT OF J. CRAIG POTTER, ASSISTANT ADMINISTRATOR FOR AIR AND RADIATION, ENVIRONMENTAL PROTECTION AGENCY, ACCOMPANIED BY FRANK PRINCIOTTA, DIRECTOR, AIR AND ENERGY ENGINEERING RESEARCH LABORATORY, RESEARCH TRIANGLE PARK; AND BRIAN McLEAN, POLICY ANALYST, OFFICE OF PROGRAM DEVELOPMENT, AIR AND RADIATION OFFICE

Mr. POTTER. Thank you very much, Mr. Chairman. I have with me Frank Princiotta, who is the director of EPA's air and engineering research lab in Research Triangle Park, North Carolina, and I also have with me Brian McLean, who is a policy analyst in my Office of Program Development in the Office of Air and Radiation.

I am pleased to be here to discuss generally clean coal technology and to comment on S. 879. I would ask to have my written statement introduced into the record, and if I might just summarize with a couple of points.

The CHAIRMAN. Yes, please do.

Mr. POTTER. The basic point that I think is obvious but that needs to be stated is that from an air pollution point of view, new technologies may well be the key to future emission reductions in this country.

Given the choices of flue gas desulfurization and coal switching, cost effectiveness especially is a key reason that we at EPA feel the need to look at these technologies both in terms of long term and short term emission reductions.

A second point, of course, is that herein if anywhere will clearly lie a key to our future energy independence, given the enormous coal deposits in this country.

Now at EPA we have tended to concentrate on retrofit applications, Mr. Chairman. Consequently, in our research program, we tend to look at individual engineered, more or less site specific kinds of applications.

I discuss a number of examples in my testimony. The LIMB project is one that we have discussed several times on the Hill, the Lime Stone Injection Multi-stage Burner project. There are others that I have also discussed in my testimony.

I will not go into detail except to say that in general they deal with E-SO_x applications and injection systems that might enhance the capability of electrostatic precipitators, NO_x reburning and things like that. They to tend to be retrofit applications.

The variables that we deal with when we do this kind of work depend upon things like the location of injection systems above the firing zones in boilers, the types of sorbents that you use, and maybe not so much the types of sorbents as the particle size, the moisture content, things like that, the temperature range for proper burning and so forth.

We also support the possible use of other technologies, Mr. Chairman. And I would include in that atmospheric fluidized bed, pressurized fluidized bed, and gasification combined cycle technologies and others.

In general there are three ways of applying SO_2 reduction technologies that might be elements of any control strategy. There would be retrofit of existing boilers, repowering of existing boilers, and advanced technologies for new power plants.

Some technologies can be used for more than one of these situations.

Senator DOMENICI. What was the second technology?

Mr. POTTER. Repowering of existing boilers. The relative role of the three ways of applying advanced technologies would strongly depend on any determination made with regard to the level and timing of emission reductions.

If major SO_2 and NO_2 reductions are required in the next 10 to 20 years, retrofit technology will dominate, we feel, with repowering playing and important role.

If the time frame for any major reduction is extended to the 30 to 40 year time frame, advanced technology for new plants may very well become much more significant. Regardless of what happens, I want to make it clear that we at EPA support the concept of advanced clean coal technologies.

The reason we are concerned about retrofit is related to what our analysis tells us about the future of coal burning power plants in this country. Because of excess plant capacity we expect continued use of conventional boiler technology for at least 30 to 40 more years.

Depending upon what we have to do in the way of controlling emissions, and I say that very carefully, therefore we tend to favor the availability of more cost effective retrofit technology.

DOE knows that and my office and Mr. Wampler's office are spending a lot of time discussing how we can better work together to better meet each other's needs. Meanwhile, the domestic policy council has asked us to take a look at a variety of issues centered around acid rain and clean coal technology.

And this is the Vice President's task force to which you heard Mr. Wampler refer. We also expect to be involved with DOE in activities associated with its new advisory panel on innovative control technology.

It is difficult to tell where one of these activities ends and the other begins. One final point, Mr. Chairman, deployment promises to be a major issue both in the short term as well as in the long term, I think. No matter what you look at here.

It is an issue that will be hard to address and one which I applaud this committee for addressing. There is a significant risk, however, I think, that in engaging in any open ended subsidy program that is not reasonably bounded in time and in terms of application.

From an environmental point of view there are also risks with any program that provides incentives to use coal without also providing certainty that emission reductions will occur.

That is basically a summary of my statement, Mr. Chairman, and we will answer your questions.

[The prepared statement of Mr. Potter follows:]

TESTIMONY OF
J. CRAIG POTTER
ASSISTANT ADMINISTRATOR FOR AIR AND RADIATION
U.S. ENVIRONMENTAL PROTECTION AGENCY
BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

MAY 18, 1987

Good Afternoon, Mr. Chairman and Members of the Committee. I am pleased to be here today to speak with you about S. 879 and the development of clean coal technologies. With me is Frank Princiotta, Director of EPA's Air and Energy Engineering Research Laboratory in Research Triangle Park, North Carolina.

Extensive United States coal reserves ensure that the United States will be self-sufficient in this vital energy resource for many years to come. We need to use that resource in a way that is protective of the public health and the environment.

Before us is an opportunity to take a major step toward resolving the conflict between coal use and environmental protection. The first major step was taken when Congress enacted the Clean Air Act Amendments of 1970. This provided a major impetus to the development and deployment of what we might call the first generation of clean coal technologies. Through coal cleaning and the installation of flue gas desulfurization (FGD) and electrostatic prcipitators (ESP) on existing and new sources, this country has substantially reduced sulfur dioxide and particulate emissions allowing coal to become our major source of electricity generation.

But both environmental needs and growing energy demands require us to develop cleaner and cheaper ways to use coal.

The President's March 18, 1987 commitment to launch a major Innovative Control Technology Program addresses both the serious issue of acid rain and the need for the commercialization of emerging clean coal technologies. We believe this $2.5 billion, five-year program can provide the impetus for deploying the next generation of clean coal technologies.

From an environmental perspective the most important application category for the focus of clean coal technology development would be the coal-fired retrofit application. Approximately 65 percent of the SO_2 emissions in the U.S. currently comes from coal-fired power plants. This figure gains additional significance because of the recent practice of rehabilitating these plants to increase their useful life. Life extension of these plants by two or more decades beyond what was previously anticipated alters one of the Clean Air Act's fundamental assumptions concerning control strategies: that new sources subject to more stringent New Source Standards will replace existing sources, thereby producing continuing reductions in overall emissions in the near-or middle-term.

Another reason for focusing on retrofit technologies stems from the concern over SO_2 and NO_x as they relate to the acid rain problem. The Joint Envoys recommended that "more consideration should be given to projects that demonstrate retrofit technologies applicable to the largest number of existing sources..., [and] special consideration should be given to technologies that can be applied to facilities currently dependent on the use of high sulfur coal."

Given that additional lower-cost approaches might be required for certain elements of the existing boiler population, the EPA has been working on technologies with the potential for low cost, moderate to high SO_2 control for existing boilers.

1. EPA has developed the LIMB (Limestone Injection Multistage Burners) process that uses low-NO_x burners for NO_x control and furnace sorbent injection for SO_2 control. LIMB, which is particularly attractive as a retrofit technology because of its low capital costs, could remove up to 50-60 percent of SO_2 and NO_x at a lower capital cost than FGD, and it requires little for retrofit.

   - The wall-fired boiler demonstration is scheduled to begin initial shake-down tests in June, 1987, and full scale extended test operations in November, 1987 at the Edgewater plant of Ohio Edison.

- A tangentially-fired boiler demonstration procurement has been initiated; however, final contract negotiations have not been concluded. This project's test phase in included in DOE's FY'88 budget request.

2. EPA has developed several other technologies for lower-cost SO_2 control, including the E-SO_x process (a low-cost, SO_2 removal technology that can be retrofitted into boilers that presently use electrostatic precipitators). The E-SO_x process uses advanced Electrostatic Precipitator (ESP) technology to free duct space needed for sorbent injection. Small pilot-scale testing shows the potential for 50-70 percent SO_2 capture in selected existing ESPs with capital costs significantly less than conventional FGD. A large pilot-scale demonstration has been selected for negotiation under the State of Ohio coal technology program with Babcock and Wilcox and EPA as co-sponsors.

3. EPA has performed basic bench- and pilot-scale development on reburning technology for NO_x control. This technology involves the addition of secondary fuel and air above the primary combustion zone. It can reduce NO_x emissions by 50 percent or more. EPA is in final negotiations for a project to demonstrate reburning technology for NO_x control on a cyclone-fired boiler. The goal is to achieve 50-70 percent NO_x control on a class of boilers that are not readily adaptable to low-NO_x burner technologies.

Relationship between Clean Coal Technologies and Acid Rain Precursor Control

There is no consensus, as yet, on whether acid precipitation precursor control is needed or the control technology strategy that may be required to achieve a given level of control. In fact, the level of any required control and its timing would have a direct impact on the technology mix that would achieve the goal at the least possible cost.

In general, there are three ways of applying SO_2 reduction technologies which might be elements of any control strategy: 1) retrofit of existing boilers; 2) repowering of existing boilers; and 3) advanced technologies for new power plants. Some technologies can be used for more than one of these situations. Each of these is briefly discussed below:

A. Retrofit of existing boilers. Retrofit technologies may be defined as those which can be added to existing boilers with relatively modest changes to the balance of the boiler system. The existing boiler population is composed of a wide range of individual units, each with specific characteristics that will influence the choice of retrofit technologies.

B. Repowering of existing boilers. An alternative approach for certain existing boilers is repowering, which typically involves replacing the existing boiler and firing system with a steam generator of another design. In many cases, repowering boosts the generating capacity of a plant anywhere from 50 to 150 percent, and may reduce emissions of both SO_2 and NO_x to levels well below some retrofit technologies and meet New Source Performance Standards.

C. Advanced technology for new plants. As existing plants are replaced by new plants with state-of-the-art SO_2 and NO_x control, emission reductions will occur. There are emerging technologies which can potentially increase the level of SO_2 control achievable on new plants beyond the 90-95 percent reduction currently achievable with FGD.

The relative role of the three ways of applying advanced technologies would strongly depend on any determination made with regard to the level and timing of emission reductions. If major SO_2 and NO_x reductions are required in the next 10 to 20 years, retrofit technology will dominate with repowering playing an important role. If the time frame for any major reductions is extended to 30-40 years, then advanced technology for new plants may become much more significant.

In addition to this work in the development of clean coal technologies, EPA has been working with the Department of Energy (DOE), both through the Clean Coal Technology (CCT) Program and in responding to the Special Envoys' recommendations. In round one of the CCT program, an EPA staff member served as a member of the Technical Evaluation Committee (TEC) for five proposals dealing with flue gas treatment and an EPA Laboratory Director evaluated the environmental aspects of all viable proposals as a consultant to the DOE's Source Evaluation Board (SEB).

With regard to the demonstration of innovative control technologies, the Joint Envoys' report recognized that a more diverse and cost-effective set of technologies would help in developing a consensus on the acid rain issue, and DOE has been given the lead in implementing the commercial demonstration recommendation of the Joint Envoys. At the President's direction, DOE will head an Innovative Control Technology Panel which will advise the Secretary of Energy on the clean coal technology program scope, criteria, and content. EPA will serve on the Panel.

Over the next five years, the Administration is committed to an aggressive program designed to commercially demonstrate and deploy the next generation of clean coal technologies that will not only lead to short- and long-term reductions in SO_2 and NO_x emissions, but also provide more economic and efficient energy options for the future.

We believe the proposed clean coal program could be enhanced by assuring at least a minimum focus on technologies capable of low-cost retrofit to existing coal boilers, such as advanced scrubbers, sorbent injection systems, and nitrogen oxide controls. Based on its track record in managing programs of this type, EPA could be helpful in the technical management of such an effort.

In addition to the five-year funding program, President Reagan asked the Vice President to have his Task Force on Regulatory Relief conduct a six-month review of Federal and State economic and regulatory programs to identify changes, under existing law, that could be made to promote rapid deployment of clean coal technologies and other cost-effective innovative emission reduction measures. A working group has already been formed and work is now underway to meet this directive. We believe these actions reflect major steps forward in achieving the objectives we share.

Comments on S.879

In many respects, S.879 and the Administration's program are similar. In particular, both initiatives recognize that an effective clean coal effort should encompass a cost-sharing effort to demonstrate the commercial potential of innovative, emerging technologies, particularly in markets where the regulatory structure increases the aversion to risk taking.

However, there are differences between the two approaches. We believe that the following are most important. First, S.879 increases the length of the program to 10 years and the cost to

$3.5 billion. We believe that national environmental and energy needs require a shorter time frame for this program.

Over the next two years, we expect major improvements in our knowledge about acid rain which should help in formulating an appropriate response to that issue, both with regard to the U.S. and to Canada. If the evidence shows the need for near-term reductions of sulfur and nitrogen pollutants from coal plants, expecially pre-NSPS plants, it is important to have an expanded menu of retrofit control and clean coal repowering options available.

Regarding our future energy needs, by the middle of the next decade, utilities will begin to confront the dual problem of an aging boiler population and the need for increasing their power generating capacity. If these companies are to take advantage of the emerging technologies to either refurbish or repower these plants, commercial demonstrations must be proving themselves by the early 1990s. Therefore, to help meet both our national environmental goals and energy needs, it is important to concentrate the clean coal demonstration effort over the next five years.

Second, S. 879 and other recent proposals include significant changes to the regulation of the financial aspects of the utility industry; changes in financial regulatory procedures raise very complex questions which need to be resolved before legislative action is taken. The Vice President's Task Force is actively engaged in analyzing these and other important issues related to regulatory incentives for clean coal technology. It is premature to take a position on such measures until that analysis is complete.

Third, both a time frame for the "demonstrations" and the amount of money proposed in S.879 appear larger than necessary. We believe that the Administration's time period of five years and funding level of $2.5 billion are appropriate to concentrate the demonstration of new technologies to meet the window of opportunity that will open in the mid-1990's.

Fourth, S.879 encompasses repowering and new source technologies as well as retrofit. This more expansive scope differs from the Envoys' Report and its emphasis on technologies that can apply to existing facilities. From an environmental perspective, we believe it is desirable that the technologies being supported provide us with some clear environmental benefits.

That concludes my prepared remarks, Mr. Chairman. Mr. Princiotta and I would be pleased to answer any questions that you may have.

# # #

The CHAIRMAN. Thank you very much, Mr. Potter. You say that for 30 or 40 years we will continue to use our present coal plants.

Do you have a median age that you could give us for existing coal plants?

Mr. POTTER. I think that the number that I use is based on the fact that most of the big plants were built in the middle 1960s to the middle 1970s, and what we are told about the lifetime of these plants is in general in the 60 year time frame.

The CHAIRMAN. Sixty years?

Mr. POTTER. That is right. That is what we are assuming for the life of the boilers.

The CHAIRMAN. So the 30 to 40 years is not the outside, that is the median?

Mr. POTTER. That is from now. Yes. The other factor of course is capacity utilization factor, and there is a lot of excess capacity out there now.

The CHAIRMAN. It is my understanding that certain types of clean coal technologies actually increase the efficiency of power plants. Is that correct?

Mr. POTTER. I think that is possible. Yes, sir.

The CHAIRMAN. And it is my understanding that scrubbers decrease the efficiency of power plants.

Mr. POTTER. By and large I think that is generally true, yes.

The CHAIRMAN. If these repowering technologies were implemented on a more widespread basis, is it possible that this would delay the need to build more baseload power plants and essentially help us meet our growing needs for electric power in smaller increments?

Mr. POTTER. I think it is possible. I think it is also possible to imagine a situation where repowering might become a substitute for a new plant which would have to meet NSPS.

I mean you have to talk about what your repowering gets you, from our standpoint, in terms of emissions reductions as well. But what you say is certainly true.

The CHAIRMAN. Do you think an incentive program such as the one providing financial assistance to utilities will help us meet the national energy and environmental policy objectives?

Mr. POTTER. In general I would think so. I think that incentives of some kind are going to have to be used in order to deploy these technologies.

But I think you have to consider whether you have a demonstration project or a demonstration effort or what amounts to in effect a utility subsidization. And you have to consider the public policy implications of that and how open ended your effort is, and so forth.

The other thing that is of course a basic requirement from our point of view, environmentally, is that it be tied as much as possible to actual emission reductions.

So, in general clearly you have to do these things but the question is, how you specifically bound them in time and in terms of application as you do it.

The CHAIRMAN. Well, you have got to subsidize from somewhere, whether it is by the ratepayers of a particular power plant or otherwise, and it seems to me that a broader subsidy makes a lot of sense because it is frequently not the people who live in the vicinity of the power plant who are at risk from the acid rain but people in a more distant area.

So subsidy seems to be the only way to me whether it is through clean coal technologies or through scrubbers. It is really the only practical way to me; it seems to me to get at the problem.

Mr. **Potter**. I do not disagree with that. I think that the issue from an environmental point of view is sort of underscored by what we are seeing in the whole acid rain debate, and that is as we learn about atmospheric dynamics, the nature of these problems, these emission problems, we learn more about the sources.

It is difficult with a broad based kind of approach to target the actual effects of an emission reduction programs. And that is a major concern.

The **Chairman**. A few years ago we passed legislation in the Senate, it did not pass the House, that, I forget what the popular name we used for that bill was, but we identified certain power plants by name, and we set about to require them to be retrofitted with scrubbers.

That was the oil backout bill. How viable is that approach? Can you still identify those power plants? And that was a pretty much straightforward subsidy bill.

Mr. **Potter**. I doubt that you could do that? One of the things that we are going to be doing and one of the reasons that I think it is important that we work through this effort with the Vice President and the domestic policy council, is that in the wake of the President's recent trip to Ottawa, we will be looking at specific efforts to try to get emission reductions in a more or less targeted kind of way and tell them what we can about that.

But I would not expect, from what I know, that you could go back and target specific facilities. I think that would be difficult.

The **Chairman**. Why is it we know less about what the specific power plants are than we did then, or are you saying it is not practical from a political standpoint for an economic standpoint? In other words, do we know as much about——

Mr. **Potter**. I think we know more. I think we clearly know more. And I think we can track these emissions back to specific plants in some cases. But it is a complex chemical process, which depends upon the makeup of the coal and it is an expensive proposition to do that.

The **Chairman**. Well, I mean if you were going to go back and retrofit, would you do it by specific plant basis or would you do it nationwide?

Mr. **Potter**. I do not know. I think we are in the process of trying to figure out exactly how we would do that in the various choices that you might look at. And that is part of what this whole process is going to be as we work through it with the vice president's task force.

For example, we learned a few years ago that achieving a 2 million ton reduction across the Canadian border night require 10 to 12 million ton reduction in terms of an acid rain program nationwide.

The business of discussing trans-boundary effects is very complicated business, and that is one of the reasons that I think it is the essence of wisdom here to make sure we know what the effects are going to be of any kind of program.

The **Chairman.** Now do you believe that the enactment of a clean coal bill such as S. 879 would preclude the enactment of acid rain control legislation?

Mr. **Potter.** I do not know. You are probably in a better position to answer that than I am, Mr. Chairman.

I think that certainly a well designed clean coal technology program, that makes sense, will do more to address the acid rain issue from a public policy standpoint than vice versa. I think that is clearly true.

The **Chairman.** Let me ask you one final question. This is a little bit off the point, but a matter of great interest to me.

And that is the greenhouse effect. Tell me in a few sentences if you can what the state of knowledge is about the greenhouse effect?

I will just tell you a scientist came by the office the other day and said that most scientists now agree that we are on a collision course with a very difficult rise in temperature and that it is happening and that it is in place and cannot be avoided.

Mr. **Potter.** I think there is general consensus that a good deal of the problem, and I would say 40 to 50 percent of the problem, results from the presence of carbon dioxide, much of which is generally believed to come from the burning of fossil fuels.

The other component that contributes significantly are the trace gases, methane, gases like that. In fact, I do not think we know a lot about the sources of those trace gases.

The **Chairman.** Well, I am not talking about the source or the reason, I am just simply talking about the dimensions of the problem.

Mr. **Potter.** Well I think it is happening and I think it is inevitable that it will happen. It is clear that we have changed the state of the atmosphere more significantly since the beginning of the industrial revolution than for the many thousands of years that preceded that.

The **Chairman.** Well, at one time I was either misinformed or the state of the information was that they did not know whether maybe the oceans would in fact absorb enough of it, they did not know whether this was a real trend, whether the direction was unmistakable or whether it was ambiguous.

Are you telling that it is very clear that the temperature of the earth is and will inevitably rise and that all of the effects of that will occur, and it is just a question of how fast?

Mr. **Potter.** I think it is clear that the temperature is rising. I do not think we know what the effects will be. We are going to be probably discussing that a good bit in the next decade or so.

I think the initial issue that we are probably going to be addressing, certainly from the standpoint of my office and the way it is managed, is a question of stratospheric ozone. These activities relate, but they are different from one another.

The **Chairman.** Senator Ford?

Senator **Ford.** Thank you, Mr. Chairman. Mr. Potter you mentioned excess capacity a few moments ago.

How much of that excess capacity, if you know, is generated by oil?

Mr. POTTER. I do not know. Can we provide that for the record?

[The information follows:]

"Excess capacity" is difficult to define particularly in deciding which plants or portions of plants are "excess." As Exhibit 1 indicates, in 1980 and 1985 capacity and utilization rates for coal-fired utility plants were higher than those of oil-fired plants. Also, if all units were to increase their capacity factors to 0.65—a nominal baseload capacity factor—considerable additional electricitly could be generated. However, using a 0.65 factor probably overstates oil-fired excess capacity because the design, heat rate, reliability, and age of many of these units make them best suited for cycling or intermediate load duty, with capacity utilization rates much less than 0.65.

Senator FORD. If you would do that, it just kind of popped out there on me.

But we have been talking here a little bit about, or you said about a 10 million pound reduction of emissions in the United States, would give a million reduction in Canada.

Now there was a report done jointly, we got it I think early part of February or sometime in February, between the U.S. National Acid Precipitation Assessment program and the Canadian Federal Research and Monitoring Coordinating Committee.

It sounds like a bank giving a teller a new title, rather than an increase in salary. But the report, entitled The Status of Canadian and U.S. Research in Acidic Deposition. Are you familiar with this document?

Mr. POTTER. Yes, sir.

Senator FORD. That report shows, as I read it, that eastern states which border Canada, the emissions of SO_2 have declined about 1 million tons, which is 10 percent in a 5 year period.

Is that basically correct?

Mr. POTTER. I think that is correct. Yes, sir.

Senator FORD. In addition the report shows that Canadian emissions have declined significantly since 1970 to 1984. Is that not correct?

Mr. POTTER. Yes, sir.

Senator FORD. Is there any reason to believe that this trend will not continue?

Mr. POTTER. I think there are reasons to believe it may not continue. I think one of the reasons it has happened is that we have seen the advent of some of the NSPS efforts.

We have also seen the disappearance almost of the price differential, so there appears to be burning of more low-sulfur coal. I think the short term impacts are that there have been emission reductions, and we have made that clear in our discussions with the Canadians.

Now as to whether it will continue in the future I think depends upon growth factors and the possible continuation or not of the price differential and so forth. Variables that we could probably discuss and, without any certainty, predict.

But there are some differences about what it is expected in the future. In general, however, I think we are coming to more of an accommodation with the coal folks and others in terms of what we expect as far as emission trends are concerned.

Senator **Ford**. In testimony before the environment committee a few weeks ago, EPA Administrator Thomas alluded to the lack of a "acid rain emergency."

Could you elaborate on what he meant and do you have any scientific studies to back up his statement, and be submitted for the record.

Mr. **Potter**. Certainly. We can submit it for the record Senator, but also I can say that from a policy point of view we have taken the position that a control program is not currently required based on what we know about the science.

[The information follows:]

Exhibit 1

Potential Increase in Fossil-fired Generation from Higher Capacity Utilization

	Coal-fired	Oil Fired
1980		
Capacity (Gw)	257.9	69.0
Base Case		
Generation (1000 twhrs)	1,175.0	214.0
Average Capacity Factor	0.52	0.35
Higher Capacity Utilization Case		
Generation (1000 twhrs)	1,482.0	384.3
Average Capacity Factor	0.66	0.64
Increase as a Percentage of Total Fossil Steam Generation	18.1	10.0
1985		
Capacity (Gw)	289.8	51.1
Base Case		
Generation (1000 twhrs)	1,395.0	86.0
Average Capacity Factor	0.55	0.19
Higher Capacity Utilization Case		
Generation (1000 twhrs)	1,726.0	297.0
Average Capacity Factor	0.68	0.66
Increase as a Percentage of Total Fossil Steam Generation	19.2	12.2

Mr. **Potter**. We have always tried to distinguish the acid rain control program need in the policy sense from whatever else might happen in the clean coal technology area or whatever.

They are related, obviously, but the point he was making is that based on what we know right now about the science, we can not state that we affirmatively would support needs for controls beyond what we have right now.

Senator **Ford**. I think we have established that clean coal technologies would make a plant more efficient.

A scrubber would decrease the efficiency of the plants, but thirdly, scrubbers only take out SO_2, they do not remove NO_x. So if you put a scrubber on you are taking out SO_2 but there is no NO_x removal at all.

Am I correct in that?

Mr. **Potter**. I think that is basically true.

Senator **Ford**. In your testimony you refer to LIMB, which is Limestone Injection Multi-stage Burner technology, whatever that might be.

I understand that the LIMB technology is going to be demonstrated as a part of DOE's clean coal number 1 by Babcock and Wilcox. Now this contract, which is number 3 out of basically 9, 2 have already come down the pike, has been sent to Congress and is in its 30 day lay-before period, as we refer to it.

I am in the process of reviewing that contract and would like for you to describe this project briefly if you would and tell us what you are hoping from this demonstration.

Mr. **Potter**. If it is all right, Senator, I think what I will do is defer to Frank Princiotta, who is actually managing this program. He can tell you a lot more in a lot more detail and more succinctly probably than I can.

Senator **Ford**. You may proceed.

Mr. **Princiotta**. The LIMB process is designed to reduce both sulfur oxides through sorbent injection in the boiler, along with nitrous oxides through the installation of low nitrous oxide burners.

The goal for this process is to achieve reductions of about 50 to 60 percent of both pollutants. The project which you refer to is our first demonstration program for this process.

Ohio Edison is the sponsoring utility. Babcock & Wilcox is our major partner. The State of Ohio is also a major contributor to this process.

The EPA program will demonstrate this process this year. We hope to start up the demonstration next month.

Senator **Ford**. You will demonstrate it next month?

Mr. **Princiotta**. Yes, our plan is to start the demonstration. We have already installed the low nitrous oxide burners.

Senator **Ford**. I want to make that point. It was ready for demonstration.

Mr. **Princiotta**. And we hope by September of this year to have the project in full operation.

The Department of Energy would supplement and augment our program by looking at some additional variables, by looking at some additional process variations, which we feel are quite important to maximize the ultimate utilization of the technology.

Senator **Ford**. Thank you very much. Thank you, Mr. Chairman.

The CHAIRMAN. Senator Domenici?

Senator DOMENICI. Thank you very much, Mr. Chairman. Mr. Potter, it dawned on me that I forgot to ask the Assistant Secretary a question. I asked the distinguished Chairman if we could submit it to him.

Nonetheless let me just raise it with you. It has come to my attention that clearly there is at least some potential in terms of cleanup for the use of natural gas in the cycle of burning coal, which could cause the emissions to be cleaner by using natural gas at the tail end of the coal combustion process.

Are you doing any work on that? First, is that not a true statement, that that might be a prospect? And if it is, are we doing anything about it?

And then we will submit a question to the secretary whether he believes some of that kind of research ought to go into the so-called clean coal technology program.

Mr. POTTER. Senator, I can not answer that. I am going to ask Frank to help me with that question.

Senator DOMENICI. Would you answer if you know?

Mr. PRINCIOTTA. Yes, we have an active project called a reburning project, which we are negotiating now for a joint sponsorship with the Gas Research Institute and the Electric Power Research Institute, and EPA.

It is aimed at demonstrating the use of what we call reburning technology, which is an approach to lower NO_x emissions by incorporating downstream of the normal combustion zone some kind of clean fuel.

Natural gas is quite an attractive fuel, and will be looked at very carefully. So it does appear that natural gas in relatively small quantities, could be quite effective in helping us decrease nitrous oxide emissions from existing coal fired power plants.

The CHAIRMAN. Will the Senator yield?

Senator DOMENICI. Yes.

The CHAIRMAN. Can you use a regular emission stream, this technology, with natural gas? Or is it limited to only certain kinds of emission streams?

Mr. PRINCIOTTA. We are talking about just about any existing coal fired power plant, where you would introduce a clean fuel like natural gas in the upper stages of the boiler, to essentially chemically reduce the NO_x formed in the first combustion zone.

This looks generally applicable, and maybe especially attractive for cyclone boilers, which are very high NO_x producers for which we have very little in the way of low nitrous oxide——

The CHAIRMAN. The point is you can just take an existing power plant, an existing dirty power plant and work on the downstream of that without having to reconfigure the whole plant.

Mr. PRINCIOTTA. That is correct, and for relatively low capital costs. We are talking about very modest capital investments.

Senator DOMENICI. That is as Senator Ford indicated, principally at this point related to cleaning up some of the nitrogen oxide, not the SO_2.

Mr. PRINCIOTTA. That is correct.

Senator DOMENICI. Nonetheless, that is a serious problem. We have in the United States a NO_x problem that is not one where we are making dramatic headway.

It remains a very viable problem out there. Does it not? Let me ask you, Mr. Potter, with reference to its cleanup, as compared with new technology that might alleviate this problem.

Nobody yet in the clean coal research has raised the issue—and I am sure that we will not go through the entire cycle on the floor without it being raised—that issue is our current method of mandating the reduction of pollutants that carries with it this tag-on based on "percentage reduction," when it comes to clean coal.

I understand the problem with reference to the political pressures. But it does appear to me that if we are serious about this that we ought to revisit the "percentage reduction" issue.

I analyze the percentage reduction issue as one that requires more scrubbers than would otherwise be necessary to reach the same level of cleanup, because we require that clean coal be reduced substantially more than coal that has higher levels of sulfur.

Now I do not want to put you in the middle of that battle if you do not care to be in it, but it does seem to me that it will surface as this kind of research program goes through.

I just wonder if you have formed an opinion as to whether we are wasting substantial amounts of resources in insisting on the percentage reduction approach to coal mix, or using cleaner coal, as we attempt to reduce the overall pollutants that are coming out of the smokestacks, principally in the older facilities and principally in the non-western part of the United States?

Mr. **Potter**. Well, as a policy matter, Senator, we have basically supported the idea of flexibility in dealing with percentage reduction for existing sources. That is, percentage reduction is a requirement in the context of the NSPS program, in order to get the emissions gains, whatever they are.

As far as the mix of coal switching versus flue gas desulfurization or other technologies like LIMB or whatever, even coal cleaning is concerned, we have not actually taken a position on that.

That is by the nature of coal a major issue because of the wide variety of coals in this country. It is something that we wrestle with all the time.

One of the reasons we support retrofit technologies and the role of research with regard to retrofit technologies is that we may well see development of technologies that could be considerably cheaper.

If you just look at the development of an NSPS requirement on a percentage reduction basis, the costs are about $1,000 per kilowatt, as compared to $200 to $300 per kilowatt just for simple life extensions.

So the economics there are very descriptive about why there is a tendency in the industry to go with life extension as opposed to opt for NSPS or go with new technologies.

So it is a serious problem and it is one that is at the heart and soul of the whole SO_2 control program. Coal variability, stack heights, all the issues that we deal with from an air quality point of view center around this whole business of the variety of coals that we have in this nation.

And it is a major part of this public policy debate, that we are going to have to continue to have to deal with.

Senator **Domenici**. The only reason I raise it, as I said, it may not become terribly relevant, but I have a hunch it will be as we move forward with any major research program.

I believe it might have more support, and as we move through with any acid rain cleanup program, it may have more support if maximum flexibility of fuels and fuel mixing was an ingredient, and you would not have to reduce any of the performance standards in that process.

You could perhaps even consider making them more stringent. We are not moving that way yet in the United States. It is all movement toward adding on to the tail end the cleanup process, and you know that.

You were not necessarily here when all that evolved as a policy, but at least I am pleased to know that you understand it and you understand its economics and I hope you understand the parochial nature of the dispute. And I think it is that.

Mr. **Potter**. I think it is important, particularly in the context of some of the discussions that we have on the acid rain issue, that others understand as well.

Senator **Domenici**. Thank you, Mr. Chairman.

The **Chairman**. Thank you very much, gentlemen. We appreciate your testimony very much.

Next we have a regulatory panel with Mr. Christopher J. Warner, deputy general counsel from the Federal Energy Regulatory Commission, and Mrs. Edwyna G. Anderson, commissioner from the Michigan Public Service Commission, who is also chair of NARUC's electricity committee, on behalf of NARUC.

Mr. Warner, I see your name first here, so why do you not lead off?

STATEMENT OF CHRISTOPHER J. WARNER, DEPUTY GENERAL COUNSEL, FEDERAL ENERGY REGULATORY COMMISSION

Mr. **Warner**. Mr. Chairman, thank you. I have a written statement which I will submit for the record.

The Chairman. Yes, that will be received in the record.

Mr. **Warner**. I appreciate the opportunity to provide technical comments to the Committee today on S. 879 and more specifically section 5 of that bill.

My comments represent those of the Commission staff only, and do not necessarily represent the views of the Chairman, the Commission or any individual members of the Commission.

As a threshold matter, it is important to note that section 5(a) of the bill ties the availability of any regulatory incentives under section 5(b) to the technology decisions made by the Secretary under 5(a).

Thus any designation of a clean coal technology by the Secretary under section 5(a) must also include a determination of which regulatory incentives, under sections 5(b), 5(c) and 6(a), will be available for the technology.

When read in conjunction with the authority of the Secretary of Energy to make such designations, the intention of section 5 appears to be to establish through the Secretary of Energy specific efficiency and reliability standards which clean coal technologies would be required to meet in order to qualify for certain rate treatment without further Commission review.

Moving on to sections 5(b)(1) and 5(b)(2), these sections would change the Commission's existing precedent concerning the prudence of utility expenditures as set forth in the *New England Power Company* case.

Under the *New England Power Company* standard, any determination with respect to the prudence of a public utility's expenditure for design, engineering or capital costs of a clean coal project or any other project, would be made only with reference to other supply alternatives which were available to the public utility when the decision to proceed with the project was made.

Under existing law, the Commission, in order to carry out its statutory obligations under the Federal Power Act, would review whether a public utility's actions in selecting a particular clean coal project as a supply alternative, were reasonable with reference to how a reasonable utility manager would have acted in the same situation, given other available supply alternatives.

With respect to section 5(b)(2), I would note that the provisions would supplement the Commission's existing regulations concerning pollution control and fuel conversion construction work in progress.

Under these existing CWIP regulations, public utilities are permitted to seek to include in rate base up to 100 percent of qualified pollution control and fuel conversion CWIP.

The Commission's existing fuel conversion CWIP regulations only applies to the conversion of facilities currently burning oil or natural gas.

They do not permit inclusion in rate base of more than 50 percent of other CWIP costs, such as converting an existing coal fired generating unit to a modernized facility which would utilize clean coal technology.

Instead, under the existing CWIP regulations at the Commission, those regulations could be employed for 100 percent of the costs only if the CWIP for the clean coal project were for qualified pollution control.

But this may not always be the case. The Commission relies on the Internal Revenue Service's regulations defining qualified pollution control facilities, which in turn incorporate by reference regulations promulgated by the Administrator of the EPA.

Therefore S. 879 would change the Commission's existing CWIP rules by allowing 100 percent CWIP for designated clean coal capital costs.

Moving on to section 5(b)(3), the bill would require the Commission to allow any clean coal capital costs to be amortized over a 5 year period.

This provision would be more beneficial to utility shareholders than the Commission's existing precedent, which would typically permit the amortization of capital costs over the expected remaining service life of a rehabilitated facility.

Absent this provision in section 5(b)(3), the Commission under the public interest requirements of the Federal Power Act would normally balance the needs of the public utility for a fast amortization period, versus the adverse affects which such an accelerated amortization might have on ratepayers.

As we interpret section 5(b)(3), however, it may be that that section is intended to permit the Secretary to exercise his or her discretion under section 5(a) to establish an appropriate amortization period, as long as that period is not less than the 5 year minimum set by section 5(b)(3). This question could use a certain amount of clarification in what is intended by the drafters of the legislation.

Moving on to section 5(b)(4), that section would require the Commission on application by a public utility to provide an incentive rate of return on any clean coal capital costs included in rate base.

As we interpret this section, it would still require the Commission to balance the needs of the utility and its shareholders for a particular level of incentives over and above those which would be commensurate with the risks of deploying the new technology, versus the needs of a utility's customers for just and reasonable electricity rates.

Section 5(b)(5) would establish a rebuttable presumption that any clean coal project expenditure is prudent.

Under section 205 of the Federal Power Act, the public utility which proposes changes in its rates is currently required to bear the ultimate burden of proof with respect to the justness and reasonableness of the proposed rate change, and is also required to bear the initial burden of going forward with evidence to demonstrate the justness and reasonableness of the rate. As we interpret section 5(b)(5), that section would shift only the initial burden to any intervenor which might seek to challenge the assertion that the expenditure for clean coal costs was prudent. But that section, as we interpret it, would not change the utility's ultimate burden of proof on the issue.

Finally, one clarification of section 5(b)(5) would be helpful. Sections 5(b)(1) and 5(b)(2) appear to provide rate base treatment and expensing of clean coal retrofit costs, without regard to prudence.

This is quite different from section 5(b)(5), which establishes a rebuttable presumption of prudence for any clean coal project expenditure.

In this regard is it important to clarify which section applies to particular types of expenditures for purposes of prudence reviews by the Commission. In other words, if the Commission must allow operating expenses and capital costs for clean coal retrofit costs, there would appear to be an ambiguity in the bill as to whether the Commission should consider the rebuttable prudence of these expenditures once they have been designated by the Secretary.

And finally, section 5(c) would permit the Commission to exempt any person from particular provisions of the Public Utility Holding Company Act and parts 2 and 3 of the Federal Power Act. This provision does appear to track similar provisions in the Public Utility Regulatory Policies Act under section 210(e).

In conclusion, Mr. Chairman, Chairman Hesse and the Commission would be pleased to continue to provide you and your staff with technical assistance and advice as you consider this critical legislation. Thank you very much.

[The prepared statement of Mr. Warner follows:]

TESTIMONY OF

CHRISTOPHER J. WARNER
DEPUTY GENERAL COUNSEL
FEDERAL ENERGY REGULATORY COMMISSION

MAY 18, 1986

ON
S.879
THE CLEAN COAL TECHNOLOGY
DEPLOYMENT ACT

BEFORE THE
COMMITTEE ON ENERGY AND
NATURAL RESOURCES

UNITED STATES SENATE

GOOD MORNING. MY NAME IS CHRISTOPHER J. WARNER, AND I AM THE DEPUTY GENERAL COUNSEL OF THE FEDERAL ENERGY REGULATORY COMMISSION. I APPRECIATE THE OPPORTUNITY TO PROVIDE TECHNICAL COMMENTS ON S.879, THE "CLEAN COAL TECHNOLOGY DEPLOYMENT ACT," AS IT RELATES TO EXISTING FEDERAL ENERGY REGULATORY COMMISSION REGULATIONS AND PRECEDENT.

MY COMMENTS REPRESENT THOSE OF COMMISSION STAFF ONLY, AND DO NOT NECESSARILY REPRESENT THE VIEWS OF THE CHAIRMAN, THE COMMISSION, OR ANY INDIVIDUAL MEMBERS OF THE COMMISSION. MY SPECIFIC COMMENTS TODAY WILL ADDRESS ONLY THE PROVISIONS SET FORTH IN SECTION 5 OF THE BILL, WHICH WOULD REQUIRE THE SECRETARY OF ENERGY TO DESIGNATE CERTAIN INNOVATIVE CLEAN COAL TECHNOLOGIES AND, FOLLOWING SUCH DESIGNATION, WOULD REQUIRE THE COMMISSION TO EMPLOY CERTAIN CRITERIA IN DETERMINING WHETHER A PUBLIC UTILITY'S RATES AND CHARGES FOR THESE TECHNOLOGIES ARE JUST AND REASONABLE UNDER SECTIONS 205 AND 206 OF THE FEDERAL POWER ACT.

AS A THRESHOLD MATTER, IT IS IMPORTANT TO NOTE THAT SECTION 5(a) TIES THE AVAILABILITY OF ANY REGULATORY INCENTIVES UNDER SECTION 5(b) TO THE TECHNOLOGY DECISIONS MADE BY THE SECRETARY UNDER SECTION 5(a). THUS, ANY DESIGNATION OF A CLEAN COAL TECHNOLOGY BY THE SECRETARY UNDER SECTION 5(a) MUST ALSO INCLUDE A DETERMINATION OF WHICH REGULATORY INCENTIVES UNDER SECTIONS 5(b), 5(c) AND 6(a) WILL BE AVAILABLE FOR THE TECHNOLOGY.

SECTION 5(b)(1) WOULD REQUIRE THAT ANY "CLEAN COAL PROJECT EXPENDITURE" FOR DESIGN AND ENGINEERING BY A UTILITY BE ALLOWED AS AN OPERATING EXPENSE. SECTION 5(b)(2) ALSO WOULD REQUIRE THAT ANY "CLEAN COAL CAPITAL COST" INCURRED TO RETROFIT, REPOWER, OR MODERNIZE AN EXISTING FACILITY BE INCLUDED IN RATE BASE WHEN INCURRED, EXCEPT TO THE EXTENT SUCH COST IS ALLOWED AS AN OPERATING EXPENSE UNDER SECTION (5)(b)(1). WHEN READ IN CONJUNCTION WITH THE AUTHORITY OF THE SECRETARY OF ENERGY UNDER SECTION 5(a) TO DESIGNATE INNOVATIVE CLEAN COAL TECHNOLOGIES AS ELIGIBLE FOR THE REGULATORY INCENTIVES IN SECTIONS 5(b)(1) AND (2), THE INTENTION OF SECTION 5 APPEARS TO BE TO ESTABLISH, THROUGH THE SECRETARY OF ENERGY, SPECIFIC EFFICIENCY AND RELIABILITY STANDARDS WHICH CLEAN COAL TECHNOLOGIES WOULD BE REQUIRED TO MEET IN ORDER TO QUALIFY FOR CERTAIN RATE TREATMENT WITHOUT FURTHER COMMISSION REVIEW.

THE PROVISIONS SET FORTH IN SECTIONS 5(b)(1) and (2) WOULD, IN CASES INVOLVING APPROVED CLEAN COAL EXPENDITURES TO RETROFIT, REPOWER, OR MODERNIZE AN EXISTING FACILITY, CHANGE THE COMMISSION'S EXISTING PRECEDENT CONCERNING THE PRUDENCE OF UTILITY EXPENDITURES AS SET FORTH IN NEW ENGLAND POWER COMPANY, 31 FERC ¶ 61,047 (1985). UNDER THE NEW ENGLAND POWER STANDARD, ANY DETERMINATION WITH RESPECT TO THE PRUDENCE OF A PUBLIC UTILITY'S EXPENDITURE FOR DESIGN, ENGINEERING OR CAPITAL COSTS OF A CLEAN COAL PROJECT OR ANY OTHER PROJECT WOULD BE MADE WITH

REFERENCE TO OTHER SUPPLY ALTERNATIVES WHICH WERE AVAILABLE TO THE PUBLIC UTILITY WHEN THE DECISION TO PROCEED WITH THE PROJECT WAS MADE.

THE COMMISSION'S INVESTIGATION INTO PRUDENCE MATTERS DOES NOT HAVE AS ITS INTENTION THE SUBSTITUTION OF THE COMMISSION'S JUDGMENT FOR THAT OF A PUBLIC UTILITY'S MANAGERS. HOWEVER, UNDER EXISTING LAW, THE COMMISSION, IN ORDER TO CARRY OUT ITS STATUTORY OBLIGATION UNDER THE FEDERAL POWER ACT TO PROTECT RATEPAYERS, WOULD REVIEW WHETHER A PUBLIC UTILITY'S ACTIONS IN SELECTING A CLEAN COAL PROJECT AS A SUPPLY ALTERNATIVE ARE REASONABLE WITH REFERENCE TO HOW A REASONABLE UTILITY MANAGER WOULD HAVE ACTED IN THE SAME SITUATION, GIVEN OTHER AVAILABLE SUPPLY ALTERNATIVES.

WITH RESPECT TO THE PROVISIONS SET FORTH IN SECTION 5(b)(2), I WOULD NOTE THAT THE PROVISIONS WOULD SUPPLEMENT THE COMMISSION'S EXISTING REGULATIONS CONCERNING POLLUTION CONTROL AND FUEL CONVERSION CONSTRUCTION WORK IN PROGRESS (CWIP), 18 C.F.R. § 35.26 (1986). UNDER THE COMMISSION'S EXISTING POLLUTION CONTROL/FUEL CONVERSION CWIP REGULATION, WHICH WAS NOT AFFECTED BY THE D.C. CIRCUIT COURT OF APPEALS' REMAND IN MID-TEX ELECTRIC COOPERATIVE v. FERC, 773 F.2d 327 (1985), PUBLIC UTILITIES ARE PERMITTED TO SEEK TO INCLUDE IN RATE BASE UP TO 100% OF QUALIFIED POLLUTION CONTROL AND FUEL CONVERSION CWIP. THE COMMISSION'S EXISTING FUEL CONVERSION CWIP REGULATION ONLY APPLIES TO THE CONVERSION OF FACILITIES CURRENTLY BURNING OIL

OR NATURAL GAS TO OTHER FOSSIL FUELS. THE COMMISSION'S CWIP REGULATIONS DO NOT PERMIT INCLUSION IN RATE BASE OF MORE THAN 50 PERCENT OF OTHER CWIP COSTS, SUCH AS CONVERTING AN EXISTING COAL-FIRED GENERATING UNIT TO A MODERNIZED FACILITY WHICH WOULD UTILIZE "CLEAN COAL" TECHNOLOGY. INSTEAD, THE EXISTING CWIP REGULATIONS COULD BE EMPLOYED FOR 100 PERCENT OF THE COSTS ONLY IF THE CWIP FOR THE CLEAN COAL PROJECT WERE FOR QUALIFIED POLLUTION CONTROL, BUT THIS MAY NOT ALWAYS BE THE CASE. S.879 WOULD THEREFORE CHANGE THE COMMISSION'S EXISTING CWIP RULES BY ALLOWING 100 PERCENT CWIP FOR DESIGNATED CLEAN COAL CAPITAL COSTS, WITHOUT REGARD TO WHETHER THEY QUALIFY AS POLLUTION CONTROL EQUIPMENT UNDER THE COMMISSION'S CURRENT CWIP REGULATIONS.

WITH RESPECT TO THE PROVISIONS OF SECTION 5(b)(3), S.879 WOULD REQUIRE THE COMMISSION TO ALLOW ANY CLEAN COAL CAPITAL COST TO BE AMORTIZED OVER A FIVE YEAR PERIOD. THIS PROVISION WOULD BE MORE BENEFICIAL TO UTILITY SHAREHOLDERS THAN THE COMMISSION'S EXISTING PRECEDENT, WHICH WOULD TYPICALLY PERMIT THE AMORTIZATION OF CAPITAL COSTS OVER THE EXPECTED REMAINING SERVICE LIFE OF A REHABILITATED FACILITY. ON THE OTHER HAND, A MANDATED FIVE YEAR AMORTIZATION PERIOD COULD, IN CERTAIN INSTANCES, RESULT IN INITIALLY HIGHER RATES TO THE THE PUBLIC UTILITY'S CUSTOMERS DUE TO EARLIER RECOVERY OF SUCH COSTS. ABSENT THE PROVISION IN SECTION 5(b)(3), THE COMMISSION UNDER THE PUBLIC INTEREST REQUIREMENTS OF THE

FEDERAL POWER ACT, WOULD BALANCE THE NEEDS OF THE PUBLIC UTILITY FOR A FAST AMORTIZATION PERIOD VERSUS THE ADVERSE EFFECTS WHICH SUCH AN ACCELERATED AMORTIZATION MIGHT HAVE ON RATEPAYERS. AS WE INTERPRET SECTION 5(b)(3), HOWEVER, IT MAY BE INTENDED THAT THE SECRETARY MAY EXERCISE HIS OR HER DISCRETION UNDER SECTION 5(a) TO ESTABLISH AN APPROPRIATE AMORTIZATION PERIOD, AS LONG AS IT IS NOT LESS THAN THE FIVE YEAR MINIMUM SET BY SECTION 5(b)(3).

SECTION 5(b)(4) WOULD REQUIRE THE COMMISSION, ON APPLICATION BY A PUBLIC UTILITY, TO PROVIDE AN INCENTIVE RATE OF RETURN ON ANY CLEAN COAL CAPITAL COST INCLUDED IN RATE BASE. THE PROVISION MIGHT RESULT IN A PUBLIC UTILITY HAVING TWO RATES OF RETURN -- AN INCENTIVE RETURN ON THE CAPITAL COST OF A CLEAN COAL PROJECT AND A NORMAL RETURN ON ITS OTHER ASSETS. ALTHOUGH THE COMMISSION'S EXPERIENCE WITH INCENTIVE RATES OF RETURN IS LIMITED, ANY INCENTIVE RETURN UNDER THIS SECTION WOULD STILL HAVE TO BALANCE THE NEEDS OF THE UTILITY AND ITS SHAREHOLDERS FOR A PARTICULAR LEVEL OF "INCENTIVES" OVER AND ABOVE THOSE COMMENSURATE WITH THE RISKS OF DEPLOYING THE NEW TECHNOLOGY, VERSUS THE NEEDS OF ITS CUSTOMERS FOR JUST AND REASONABLE ELECTRICITY PRICES.

SECTION 5(b)(5) OF S.879 WOULD ESTABLISH A REBUTTABLE PRESUMPTION THAT ANY CLEAN COAL PROJECT EXPENDITURE IS PRUDENT UNDER SECTION 205 OF THE FEDERAL POWER ACT, A PUBLIC UTILITY

WHICH PROPOSES CHANGES IN ITS RATES TO REFLECT INCREASED CAPITAL COSTS, IS CURRENTLY REQUIRED TO BEAR THE ULTIMATE BURDEN OF PROOF WITH RESPECT TO THE JUSTNESS AND REASONABLENESS OF THE PROPOSED RATE CHANGE, AND IS REQUIRED TO BEAR THE INITIAL BURDEN OF GOING FORWARD WITH EVIDENCE TO DEMONSTRATE THE JUSTNESS AND REASONABLENESS OF THE RATE. THE PROVISION OF SECTION 5(b)(5) WOULD SHIFT THIS INITIAL BURDEN TO ANY INTERVENOR WHICH MIGHT SEEK TO CHALLENGE THE ASSERTION THAT THE EXPENDITURE IN THE CLEAN COAL PROJECT WAS PRUDENT, BUT WOULD NOT CHANGE THE UTILITY'S ULTIMATE BURDEN OF PROOF ON THE ISSUE.

ONE CLARIFICATION OF SECTION 5(b)(5) WOULD BE HELPFUL. SECTIONS 5(b)(1) AND (2) APPEAR TO PROVIDE RATE BASE TREATMENT AND EXPENSING OF CLEAN COAL "RETROFIT" COSTS WITHOUT REGARD TO PRUDENCE. THIS IS QUITE DIFFERENT FROM SECTION 5(b)(5), WHICH ONLY ESTABLISHES A "REBUTTABLE PRESUMPTION" OF PRUDENCE FOR "ANY CLEAN COAL PROJECT EXPENDITURE." IN THIS REGARD, IT IS IMPORTANT TO CLARIFY WHICH SECTION APPLIES TO PARTICULAR TYPES OF EXPENDITURES FOR PURPOSES OF PRUDENCE REVIEWS BY THE COMMISSION. IN OTHER WORDS, IF THE COMMISSION MUST ALLOW OPERATING EXPENSES AND CAPITAL COSTS FOR CLEAN COAL RETROFIT COSTS, THERE WOULD APPEAR TO BE AN AMBIGUITY IN THE BILL AS TO WHETHER THE COMMISSION SHOULD CONSIDER THE REBUTTABLE PRUDENCE OF THESE EXPENDITURES, ONCE THEY HAVE BEEN DESIGNATED BY THE SECRETARY.

FINALLY, SECTION 5(c) WOULD PERMIT THE COMMISSION TO EXEMPT ANY PERSON FROM THE PROVISIONS OF THE PUBLIC UTILITY HOLDING COMPANY ACT AND PARTS II AND III OF THE FEDERAL POWER ACT UPON A PROPER SHOWING AS SET FORTH IN SECTIONS 5(c)(1) AND (2). THIS PROVISION APPEARS TO TRACK THE PROVISIONS OF SECTION 210(e) OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WHICH PERMITTED SIMILAR EXEMPTIONS WITH RESPECT TO COGENERATORS AND SMALL POWER PRODUCERS.

IN CONCLUSION, CHAIRMAN HESSE AND THE COMMISSION WOULD BE PLEASED TO CONTINUE TO PROVIDE YOU AND YOUR STAFF WITH TECHNICAL ASSISTANCE, AS YOU CONSIDER LEGISLATION ON THIS CRITICAL ISSUE FOR OUR NATION'S ENERGY POLICY. I WOULD BE HAPPY TO ANSWER ANY OF YOUR QUESTIONS.

The CHAIRMAN. Thank you very much, Mr. Warner.

Ms. Anderson?

STATEMENT OF EDWYNA G. ANDERSON, MICHIGAN PUBLIC SERVICE COMMISSION, ON BEHALF OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS, ACCOMPANIED BY MICHAEL A. FIELEK, ELECTRICITY COMMITTEE STAFF CHAIR, MICHIGAN PUBLIC SERVICE COMMISSION; AND JOHN M. FLUMERFELT, DIRECTOR OF CONGRESSIONAL RELATIONS, NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Ms. ANDERSON. Thank you very much, Mr. Chairman. I am here on behalf of the National Association of Regulatory Utility Commissioners as its Chair of its Committee on Electricity.

With me are Michael Fielek, who is the chairperson of the staff subcommittee on electricity of that body, and John Flumerfelt, who is the director of Congressional regulation for NARUC.

I would like to indicate, as you well know, that NARUC is the national representative of the 50 state commissions responsible for, among other things, the economic regulation of utilities now operating fossil fuel fired electric generation stations that are so central to this whole subject of acid deposition.

We are very appreciative of the opportunity to present NARUC's views on clean coal technology and to express some of the concerns of regulators concerning the battle to control acid rain.

Unfortunately our organization has not yet had time to meet and adopt a formal position on S. 879. But as chair of the committee on electricity, I am in a position to assure you that the subject of acid deposition has been on our agenda for the last 2 years and the subject of clean coal technology will be high on our agenda during the upcoming summer meetings which will be held in July.

Those deliberations, which to date I believe, are of relevance to your current activity, show what I believe to be NARUC agreement on the following points. Many regulators and rate payers nationwide are deeply concerned with the acid rain problem and are willing to continue to provide support toward its resolution.

The NARUC supports the development of clean coal technologies and advocates Federal co-sponsorship of such programs, realizing that utilities can not assume this risk alone on an issue with international ramifications.

Incentives for clean coal technology development should not be mandated but should be left to the discretion of regulators. The bills now before Congress represent a substantial change in regulatory policy.

Any any presumption of prudence, rebuttable or otherwise, would be strongly opposed by the NARUC and should be deleted from such legislation.

Clean coal technology should be developed concurrently with other potentially beneficial technologies, while near term solutions are actively pursued in the interim.

The NARUC believes it must be represented on the advisory panel proposed by the President to review clean coal technology projects and in any other appropriate capacity. We urge your support in this regard.

Retention of the flexibility needed to address these problems in the context of local conditions, is a must for state regulators to assure cost control in behalf of ratepayers.

In conclusion we feel strongly that state regulatory agencies are best able to determine the prudence of actions of utilities within their jurisdictions.

We seek to work with the Federal government and our utilities to solve the acid deposition problem, but we want to be partners in the solution rather than legally pre-empted bystanders to a parade of expensive projects of undemonstrated value.

Thank you, Mr. Chairman.

[The prepared statement of Ms. Anderson follows:]

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

TESTIMONY OF EDWYNA G. ANDERSON
MICHIGAN PUBLIC SERVICE COMMISSION

ON BEHALF OF THE

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
1102 INTERSTATE COMMERCE COMMISSION BUILDING
TWELFTH STREET AND CONSTITUTION AVENUE, N.W.
POST OFFICE BOX 684, WASHINGTON, D.C. 20044
TELEPHONE (202) 898-2200

CLEAN COAL TECHNOLOGY

MAY 18, 1987

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NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

SUMMARY OF TESTIMONY

Before the Senate Committee on Energy and Natural Resources

May 18, 1987

Although the NARUC does not yet have a formal position on either of the clean coal bills (S. 879, S. 911) now before this Committee, the following points are stressed:

- Regulators and ratepayers nationwide are deeply concerned with the acid rain problem and are willing to provide support toward its resolution.
- The NARUC supports the development of clean coal technologies and advocates federal co-sponsorship of such programs, realizing that utilities cannot wholly assume this risk.
- State agencies can participate in this partnership by creating a regulatory environment which encourages prudent investment.
- State regulators are concerned, however, that the bills now before Congress would create "regulatory incentives" for utilities to shift operations toward the federally-regulated sector, severely impacting wholesale rates for electricity.
- The bills now before Congress represent a substantial change in regulatory policy, and any presumption of prudence, rebuttable or otherwise, would be strongly opposed by the NARUC and should be deleted from such legislation.
- Clean coal technology should be developed concurrently with other potentially benefical technologies, while near-term solutions are actively pursued in the interim.
- State regulators should retain the flexibility needed to address these problems in the context of local conditions.

Mr. Chairman and members of the Committee, I am Edwyna G. Anderson, Commissioner of the Michigan Public Service Commission, member of the National Association of Regulatory Utility Commissioners (commonly known as the NARUC), its Executive Committee and Chair of its Committee on Electricity and Subcommittee on Nuclear Waste Disposal. I am testifying today on behalf of the NARUC and am accompanied by Electricity Committee Staff Chair, Michael A. Fielek, also of the Michigan Commission, and NARUC's Director of Congressional Relations, John M. Flumerfelt.

As you may know, the NARUC is a quasi-governmental, non-profit organization founded in 1889, as the national representative of the 50 State Commissions responsible for, among other things, the economic regulation of utilities now operating the fossil fuel-fired electric generating stations so central to the acid rain debate. These State Commissions have been charged under law with the task of ensuring that the power provided by such generating stations is reliable and reasonably priced -- in short, that the public interest is protected.

I appreciate your invitation to present our views on clean coal technology, and to express some of the concerns of regulators concerning the battle to control acid rain. Unfortunately, the NARUC has not yet had time to meet and adopt a formal position on the clean coal bills, S. 879 and S. 911, recently introduced by your distinguished colleagues, Senator Byrd and Senator Durenburger, respectively. As Chair of the NARUC Committee on Electricity, however, I am in a position to assure you that the subject will be high on our agenda during our upcoming Summer Meetings. My remarks at this time are thus restricted to areas in which there appears to be general agreement, and I will comment on certain aspects of the bills which are likely to cause considerable debate among our members.

The subject of acid deposition evokes as many views among regulators as it does among members of the Congress, depending upon whose ox is being gored. The issue is divisive, but must be dealt with by the nation's policymakers. The debate has lasted many years, and the issue is not likely to subside of its own accord -- neither is the problem. Acid rain exists and is harming the environment. This is a given. Control of the sulphur dioxide and nitrous oxide emissions that cause acid rain will be expensive. This, also, is a given, as is the fact that the costs of any emission control program will undoubtedly be paid for by taxpayers and electric ratepayers.

As responsible regulators, it is our obligation -- as it is yours -- to ensure that any control program, whether in the form of clean coal technology deployment or the implementation of more stringent emission standards regarding existing facilities, is both cost-effective and equitable. It would appear that reasoned decisionmaking would dictate a balanced approach which utilizes a combination of all available solutions. The NARUC, as representatives of ratepayers, ought to be involved at all levels of planning and process through full participation in this and all related projects, and should thus be represented on the panel proposed by the President which is to be created by Secretary of Energy Herrington.

Our commitment to this issue is demonstrated by the adoption of a resolution on acid rain by the NARUC Executive Committee in February of this year. Although general in nature, the resolution represents nearly two years of intensive effort to arrive at a consensus. Given the competing interests of the 50 States on an issue as controversial as this, getting a resolution through the NARUC Committee process was no small feat, and is reflective of the importance of the subject to us all.

Taking into consideration a range of views from coal-mining states to those concerned essentially with the environmental fallout, Congress will have to cope with divergent views in similar fashion as regulators must in the ratemaking process--by balancing the equities and arriving at a judgment that satisfies no one completely, but brings the greatest good attainable.

One issue on which NARUC members seem to agree is that federal co-sponsorship is necessary in the research and development of clean coal technologies. In our February resolution, a copy of which is attached, the NARUC called on Congress "to appropriate sufficient funds for the scientific research and commercial development of the technologies which are necessary to develop and implement the most cost-effective means of reducing acid deposition. . . ."

We believe that federal support and incentives are necessary to insure the development and commercialization of clean coal technologies, realizing, as regulators, that few electric utilities are in a position to assume all the risk of experimentation. Regulators participate in this partnership by creating a regulatory environment which encourages prudently incurred investment, and by insuring that such investment is in the ratepayers' interest.

We, as a society, decided long ago to treat the electric utilities as regulated monopolies designed to provide reliable service at minimum cost. Unfortunately, the twin goals of reliability and minimum cost are inconsistent with any attempt to impose on a utility substantial risk that does not also afford commensurate benefits to the utilities and their ratepayers. Such risks are inherent in the commercial application of experimental clean coal technology.

It was precisely to avoid excessive risks such as these that an elaborate regulatory structure for the electric utility industry was established, and without federal co-funding, the commercial development of clean coal technology is an activity in which the risk is greater than the potential gain. Prudent regulatory policy, combined with federal support for research and development, are the cornerstones on which the answer to this difficult problem will be based.

The issue of near-term versus long-term technologies to reduce emissions is central to the current debate. Reduction of acid rain precursors is a very immediate concern to many interested parties, some of whom have called for a reduction of sulphur dioxide emissions of up to 10 million tons per year. One way to approach this is by retrofitting existing plants. The technology to do this exists, but at a very high cost. In my State alone, it is estimated that the installation of scrubbers on the major coal stations could cost 800 million dollars. On the other hand, one wonders if it is prudent to defer the resolution of such an important problem until such a time as the new technology is up and running.

While I have no answer to that question, I believe firmly that the individual states need the flexibility to address their pollution control problems so that the characteristics of each generating station can be taken into account in selecting the ost appropriate technology. State regulators should thus be nvolved at all levels of decisionmaking. Unfortunately, Section (b) of Senator Byrd's bill (S. 879) would effectively tie the ands of State regulators by giving to the utilities a rebuttable resumption of prudence concerning their investment in clean oal-related programs. Shifting the burden of proof away from tilities in this manner represents a substantial change in istorical regulatory policy which should be considered carefully hrough informed public debate. This is a provision which the ARUC would strongly oppose, and which should be deleted from the ill.

s laudable as the bill's purpose is -- in encouraging the evelopment of an obviously beneficial technology -- it is not lear that such a dramatic "incentive" is necessary. It may even e arguable that a presumption of prudence is counter-productive, y giving utilities too much freedom to experiment. The assumption of a reasonable amount of risk is an incentive to apply investment efficiently. Imagine, if you will, the consequences f giving the utilities a presumption of prudence concerning their investment in nuclear generating facilities!

We are also troubled by the fact that both bills provide utilities with a "regulatory incentive" to shift their operations away from State regulatory authority into the federally-regulated arena by allowing any clean coal project expenditure as an operating expense. As this Committee is well aware, this is an issue which is already drawing nationwide attention, as exemplified by the Grand Gulf case. And it is plainly obvious that any costs allowed by the FERC as an "operating expense" are going to be passed through directly to utility ratepayers. The effect that each of these bills would have on wholesale rates for electricity could be immense.

It is also possible that the adoption of either of these bills would preclude any of the short-term acid rain solutions which might otherwise be available. Giving utilities such powerful incentives to develop clean coal technology is likely to impede the development of other solutions to this complex problem. This, in my view, is not responsible regulatory policy, nor is it warranted. Clean coal technology is well on its way toward commercial viability, and regulators are currently able to give encouragement and security to utilities who make investments which are in the public interest.

In conclusion, let me again stress that we acknowledge and support responsible environmental standards and consider it important that the ratepayer contribute to the solutions to the acid rain problem. We feel strongly, however, that State regulatory agencies are best able to determine the prudence of actions of utilities within their jurisdictions, and that the burden of proof concerning prudent investment should remain with the utilities. We seek to work with the federal government and our utilities to solve the acid rain problem, but we want to be part of the solution, rather than bystanders to a parade of expensive projects, no matter what the rationale.

We believe that ratepayers and taxpayers are deeply concerned with this issue and willing to support the goal of reducing acid rain. The clean coal technology program is _one_ of the potentially available tools with which to do this, and one which should be actively pursued. We, as regulators, ask, however, that we retain the flexibility to address the problem in the context of our own regional conditions, and that we be able to provide input into decisionmaking that will dramatically affect our ratepayers and citizens, as we move forward to control this significant environmental problem.

Thank You.

Resolution on Acid Rain

WHEREAS, Congress has been considering legislation which is intended to moderate the environmental impact of "acid rain" by requiring increased control of emissions of sulfur dioxide and oxides of nitrogen; and

WHEREAS, The adoption of such legislative proposals in all probability would cause many electric utilities to incur substantial additional costs in order to comply with these new emissions standards; and

WHEREAS, Such additional costs would ultimately be borne by utility ratepayers; and

WHEREAS, Previous legislative proposals to establish a mechanism for funding the additional costs which will be incurred by certain electric utilities to comply with any new emissions standards have improperly encroached upon the authority of State commissions to set retail electric rates; now, therefore be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC), assembled in it Winter Committee Meeting in Washington, D.C., urges Congress to appropriate sufficient funds for the scientific research and commercial development of the technologies which are necessary to determine and implement the most cost effective means of reducing acid deposition; and be it further

RESOLVED, That legislative proposals should give adequate consideration to the need to develop an implementation strategy which will permit electric utilities to meet any new emissions standards in the most economic and efficient manner; and be it further

RESOVLED, That Congress leave the States sufficient flexibility to apply regulatory principles which constitute the most efficient and least cost means of implementing changes in existing air emissions standards; and be it further

RESOLVED, That the Executive Committee supports the principle that any acid rain legislation be based upon findings supported by scientific evidence; and be it further

RESOLVED, That Congress take into account the economic impact on electric utilities and their customers and give proper recognition to the role of State commissions in setting retail electric rates.

Sponsored by the Committee on Electricity
Adopted February 25, 1987

The **Chairman**. Thank you very much, Ms. Anderson.

Mr. Warner, as I read you, you are saying that you are not at all sure that FERC or other regulators under present law could in effect approve as being prudent the choice of technologies which might be more expensive even though they achieved another national goal of clean air, that we really need a change in the law to effect that purpose.

Am I correct?

Mr. **Warner**. Mr. Chairman, we have not looked at to what extent the Commission could adopt such a regulatory provision by rulemaking.

I think it is safe to say that the Commission does have substantial rulemaking authority. Under its current regulations in place however, such incentives would not be available under the CWIP regulations or otherwise.

And if we were to seek to promulgate such incentives by rulemaking, those rulemakings would have to be based on substantial evidence in the record.

So we would have to wait for the comments and review the evidence in the record as to balancing the needs for just and reasonable electricity rates with overall national needs for a cleaner environment.

The **Chairman**. I mean, do you think that it is within your charter, your legislative charter to approve another national need other than just and reasonable by saying that it ought to be important to have clean air, for example?

Mr. **Warner**. I think it is safe to say as we get further and further away from cost of service ratemaking, the Commission's authority becomes less and less clear.

So to the extent that we would be looking at considering benefits other than direct cost benefits to ratepayers, it would become more difficult to allow such incentives.

The **Chairman**. Would you comment on the possibility or the advisability, not only in the context of this legislation but in the context of all new power plants, of having the capability of approving certain choices in advance.

Keeping in mind that you could not approve everything, because they may build it sloppily or they may be too slow or cost overruns and all of that.

But why can FERC not, and indeed local state regulatory commissioners, have a procedure for having certain choices approved in advance? And then litigate that question of whether you ought to use clean coal technologies or a gas fired plant or a nuclear plant or whatever, or a certain size addition.

Have that question litigated in advance so that then they can go ahead at least as to that discreet question, have that approved in advance. Is that practical or advisable?

Mr. **Warner**. I think there are really two components of that, Mr. Chairman.

One is the extent to which we can avoid applying retroactive prudence reviews. In fact, the Commission in the *New England Power* case has adopted a no-hindsight approach to prudence. That is the commission has stated that costs would be considered prudent if they were those which a reasonable utility management would have made in good faith under the same circumstances, and at the relevant point in time that faced that particular utility management. So that is one component of it.

The second component of it, I think, is the extent to which the Commission has the authority to pick out particular technologies or particular costs, such as pollution control costs, and allow for construction work in progress rate treatment for those costs. And the Commission has under its CWIP regulations exercised that authority to allow pollution costs to be included in rate base as part of construction work in progress. So I think the Commission does have substantial authority to do that.

On the other hand, the Commission's jurisdiction, of course, is limited, and if you are speaking of generating facilities, the major part of the jurisdiction over generating facilities is certainly left to the state utility commissions.

The CHAIRMAN. Ms. Anderson, I understand most state utility commissioners adopt the New England rule about no-hindsight. At least I think they apply that rule. Do they not?

Ms. ANDERSON. It varies from state to state, Mr. Chairman.

For example, in Michigan we have attempted throughout the 7 years that I have been on the commission and before that to get within our framework siting legislation, for the kind of advance approval that you are talking about.

We have been unable to move that through the legislature for reasons that perhaps the utility companies and others can describe better than I. I think it is important to recognize, however, that there are some things that you simply cannot approve in advance.

We had had very poor experiences in some states with regard to the construction of nuclear power plant facilities, for example.

And the cost estimates have been way off base, and if we had given outright approval we would not be able to look at the very kind of thing that you perceive to be a regulatory impediment, and that is whether or not management has been adequate and accurate in its handling of the circumstances as we look to determine whether or not these costs ought to be added to rate base.

I think you will find the same kind of problems arising out of a technology or technologies that are not yet fully explored. For example, if you wanted to provide a 50 percent grant of, say, $20 million on a $40 million facility that is estimated to be $40 million for clean coal technology.

And it turns out to be $100 million because of cost overruns, and you leave in this phrase about rebuttable presumption and so on, we are stuck with passing on to the ratepayers costs that have not been adequately reviewed and where prudence has not been a major consideration.

The CHAIRMAN. But the problem is there is a perception in the utility industry that they are going to be second-guessed on decisions which were prudent when made, and even though there is this no-hindsight rule, in effect there is an operational hindsight rule where they go in and because of TMI and the new regulations and the delays and the political unpopularity of a particular choice, whether it be nuclear power or others, they in wholesale lots are finding decisions to be imprudent.

Now without relationship to who is right in that controversy, it is clear that that is a perception, and in turn it will affect all kind of decisions.

I mean, if I were a utility executive, and somebody were saying, well, we will go the clean air route. We can not guarantee you that they will not come in and find that you were imprudent later on. But do it because it is patriotic and we think it is a good thing to do.

Well, I think they would not do it, because they would think, my friendly public utilities commissioner is simply not going to approve this, or may not approve it. And if he does not approve it, my taxpayers pay it.

And if we do not put it in, well, nothing is going to happen. We do not get fined. We do not go to jail. We may or may not take our chances with acid rain legislation.

But if we are required to come in and retrofit with acid rain, surely that will be rate-based, whereas this other decision might be ex post facto. They may take it away from us.

Now how would you respond to that?

Ms. ANDERSON. Several things come to mind. The first being that we are requesting that we be partners in this process.

One of the things that we have found is that we are not included in the whole business. We were not, for example, when the DOE began looking at the 51 projects that it had before it and it narrowed them down to nine. We were nowhere in that process.

I heard Mr. Wampler say here today that one of the things that the DOE would like to do, and it is in his written testimony as well, is to meet and explain the importance of this project to state regulators.

That kind of explanation we do not need. What we need is the opportunity to meet and discuss and have some input into the whole process at the outset.

Now that certainly would limit the after-the-fact kind of review that would come, that puts us in a difficult position, because it makes us in a sense have a role with regard to the whole management thrust.

But we need to be partners in this process to explain the regulatory process and get it into the mill in terms of the decisions that are made at the outset. Because we are going to ultimately be responsible for passing on the requirements that ratepayers pay this money.

At the local level we are losing major industry because of electric bills, gas bills, telecommunications bills that are too high. It is our responsibility to keep our economies in order, and we have to bear that in mind as we make these judgments.

The CHAIRMAN. But you are a full partner in this policy making that is going on right at this moment.

And I would like to get your advice on how can we encourage people in your position, the regulators, to approve clean coal technologies. I would like to know whether we need changes in the law or what kind of hortatory language or what kind of change do we need, or do we simply need to talk or what do we need to do?

Ms. ANDERSON. Well, we think that this effort to go after the problem, the whole business of clean coal technology is an important one.

We are in agreement that it ought to be pursued. We do not agree with the idea of removing flexibility from the states to handle their local regulatory problems. We do not approve of the rebuttable presumption idea.

The CHAIRMAN. Why is that bad? I mean, it would be only a presumption, and it would be limited to that question of clean coal, that specific question. Not the question of whether they hired the wrong contractor and were negligent in overseeing, and all of those questions.

But just on the question of the choice of clean coal technologies, why should that not be a rebuttable presumption?

Ms. ANDERSON. First of all there are numbers of technologies, we do not know what is ultimately going to land.

We think that any technology ought to have widespread application, that it ought to improve efficiency, and that it ought to be cost-effective.

The CHAIRMAN. Well, how can it have widespread application if it does not get approved in advance?

Ms. ANDERSON. I am sorry, but I do not understand.

The CHAIRMAN. How can we get widespread application of a promising clean coal technology if you all do not widely approve it?

Ms. ANDERSON. We will not be able to approve something about which we know nothing. And I am saying to you, let us into the process at the outset. That is whole problem.

The CHAIRMAN. Well, I mean, this is the outset. We are here right now.

Ms. ANDERSON. And we are very grateful for this involvement.

The CHAIRMAN. You see, our problem is, we hear the testimony from these experts who say clean coal technology is very promising, that it is cost-effective.

I mean, we have a Cool Water plant out there that I have seen, that costs too much now, but they tell us we can bring down the cost, and it will measurably, not only measurably but almost completely clean up the SO_2 and more than half of the NO_x, and it just does wonderful things.

And we will have estimates, for example, I hope we will have estimates, that replications of that kind of technology are cost-effective. So we come to the local commissioners and we say, all the science looks good.

And you would say, in effect, well, if it works and saves money that is fine. If it does not, your stockholders are going to pay for it. Because it is not widely used.

Now my question to you is, how can we get something that is promising widely used without putting something like a rebuttable presumption in the law?

Ms. ANDERSON. Well, I think it does not have to be both promising and widely used at the same time. We are saying that the application of it ought to ultimately become widely used.

But I would have to call to your attention the very dilemma that we have faced with regard to nuclear power plant construction, with regard to nuclear waste disposal, the billions of dollars that we are being called on at every juncture to provide to programs about which we know little in terms of the ultimate costs and the ultimate viability.

I am simply suggesting to you that we want a little more this time around if we can possibly get it, but I think that you will find the steps that the states would take would be to be receptive to the extent that they can be.

Now bear in mind that we represent coal producing states, we represent coal burning states, we represent states that do not use coal that are feeling the environmental fallout.

We have been discussing this for two years now. We have tried to reach consensus, and I am saying to you that we have got as much a range of concern and interest as you have in the Congress.

And we would like to work with you to work through these problems.

The **Chairman**. Well, I wish you would continue to think about this particular problem of how we can encourage it. We do not want to cram things down the throats of local regulators by any means.

And we have done some, in my judgment, some imprudent things. For example, I think we went overboard on PURPA by requiring electric power companies to purchase some electricity frequently which is not cost-effective and not necessarily in the national interest.

Some details of that program that we did not really know exactly how they were going to work out. I am frank to tell you I do not know how or when or indeed if we are going to change them legislatively. We have not made that decision yet.

But we do not want to make those kind of mistakes. But we need really to encourage the use of these clean coal technologies to the extent that they do look promising and we need a criteria for that so we will be hoping to talk to you and Mr. Warner more as time goes on with suggestions as to how we might do that.

Ms. **Anderson**. We will be meeting, Mr. Chairman, in July as a full committee. We are a 21 member committee representing 21 of the states. We will be discussing this in detail.

We have not had that opportunity. I would be happy to submit to you in writing or otherwise feedback from that session and any others that we will follow up with.

The **Chairman**. Well, please do because your advice is very important to us.

Ms. **Anderson**. Thank you.

The **Chairman**. Senator Ford?

Senator **Ford**. Thank you, Mr. Chairman. Mr. Warner, let me ask you a question or two, and then I want to ask Ms. Anderson a question or two.

Mr. Warner, you state that the risk of deploying new technology must be balanced by the needs of the customers for just and reasonable electricity rates or prices.

With the multiple objectives of building a cost-effective and reliable electricity supply that is environmentally sound, and that contributes to our national energy security. How would you go about balancing these objectives?

Mr. **Warner**. Senator Ford, it is a very traditional balancing test that the commission goes through, balancing the risks to the shareholders of the utility in terms of investing in a particular technology or a particular form of service against the needs of the consumers for adequate supplies at reasonable cost.

Way back in the *Hope Natural Gas Company* case, the Supreme Court said that the Commission need not rely solely on cost factors, that it can consider non-cost factors. And within non-cost factors, I would think some of the overall nationwide environmental benefits could be included.

At the same time, in every rate case you have different perceptions by the customers and the company as to what is a just and reasonable rate, what cost and non-cost factors should be considered. So it is certainly subject to a certain amount of litigation in every rate case that is filed by a utility before the Commission.

Senator **Ford**. Can these objectives be met under the current regulatory scheme?

Mr. **Warner**. I think it really depends on the specific proposals made by a particular utility. It is very fact-based.

On the one hand, we do have CWIP treatment for pollution control costs, and that is based on certain pollution control equipment certified by the EPA and subject to amortization under IRS regulations.

On the other hand, when a utility comes in and proposes some novel technology, or a new form of generating electricity, it will depend in every specific case on how the customers look at that technology and what is litigated in the particular case.

So I could not generally tell you whether the Commission has authority to deal with this administratively in every case, because I think it is very fact-bound, based on the technology and the utility and its ratepayers.

Senator **Ford**. I am sure you have looked at S. 879 with a fine tooth comb, probably, before coming up here today.

Mr. **Warner**. Yes, sir.

Senator **Ford**. How does this particular piece of legislation work in your opinion toward achieving these objectives?

Mr. **Warner**. Senator, if I read the intentions behind the legislation correctly, the intentions are to, in effect, delegate to the Secretary of Energy many of the prudence determinations that have been traditionally made by the Commission on a case by case basis.

Here in the legislation the Secretary of Energy is required to consider the reliability, efficiency, and cost-effectiveness of the technology before designating it.

And as I read it, that would in effect be equivalent to a prudence determination by the Secretary as to the effectiveness and the cost factors involved in the technology.

Once that designation were made, then the legislation would establish the particular rate treatment that the commission would be obligated to provide the designated technologies.

Senator **Ford**. Is that all bad, or all good, or is it no good or all good, or what?

Mr. **Warner**. We do not have comments on the merits either way, but I think it is safe to say that the effect of this legislation would be to remove from our jurisdiction much of the case by case prudence reviews that the Commission is required to perform in particular rate cases.

It would remove the uncertainty and unpredictability as to the treatment of the cost effectiveness of the technology itself. Instead, after the Secretary of Energy has made that designation, there would be prospective certainty as to the issues of efficiency and reliability and cost effectiveness.

Senator **Ford**. Ms. Anderson, let me compliment you. You come with a high degree of confidence from your fellow commissioners and I am delighted that you are here, and I understand that you want input.

At some point you understand when you make a decision all the input is over.

Ms. **Anderson**. That is right.

Senator **Ford**. And that falls and they either take you to court, accept it or whatever.

And so we here have all the input we can and at some point we have to make a decision. That is the reason all these lights are on, you know. We are doing it in sunshine here.

So I want you to know that I understand, having been a governor, having appointed the commissioners, understanding their independence and what they have to do, it becomes a knotty problem, balancing the needs of industry with the desire of the ratepayer for a lower rate.

So let us go down two or three questions here and see how we can come out. It is my understanding that most types of clean coal technologies increase the efficiency of power plants. Is that your understanding also?

Ms. **Anderson**. Not necessarily, sir.

Senator **Ford**. I did not say all, now.

Ms. **Anderson**. Right. I could not say most. I have only had an opportunity to look in the last few days at those programs that have been submitted to the DOE, the nine, and it seems to me that there is some variance there.

Senator **Ford**. Would you say that certain technologies, certain types would increase the efficiency of power plants?

Ms. **Anderson**. Yes, I certainly could agree to that.

Senator **Ford**. My efficient staff here has reminded me that the first group of going through for new technologies is not designated toward repowering, the second group will be.

So let us talk about repowering technologies a little bit, which we have not gotten to yet, but see how it factors in.

Would the use of these repowering technologies help us meet our growing need for electricity supply in smaller increments, whereby we could match supply and demand more closely?

Ms. **Anderson**. Well, much would depend, I think, Senator Ford, on the age of the facilities that you are talking about, whether or not those are the ones that would require the kind of attention that you are talking about.

I am getting way over my head with regard to the technical aspects because I do not normally deal with that. But we certainly would have to give consideration as to whether or not it would not be more costly, for example, to retrofit or repower some existing facilities than it would be to construct new ones.

So those are considerations that would have to be made by management according to the information that we have been given.

Senator **Ford**. Well, have you tried to evaluate the clean coal technologies or the new ones, versus scrubbers and what is the cost of scrubbers? That is a basically known cost, is it not?

Ms. **Anderson**. Yes.

Senator **Ford**. And new technologies, hopefully, will be retrofit. They will be less costly, they will be more efficient. Those are things that we are looking at here down the pike.

Have you tried to balance any of those yet against the known, against the unknown?

Ms. **Anderson**. Well, there is so much that is still unknown. I would tell you, for example, that in the state of Michigan, we have gone to low-sulfur coal as a means of trying to adjust to the whole problem.

That means that we have spent substantially more money, our ratepayers have, for addressing the problem than many of the surrounding states.

On the other hand, if we were required right now, because 78 percent of our facilities are coal-burning facilities, if we were required right now to install scrubbers, that would be to the tune of roughly $800 million.

And I want to say to you that when you are talking about ratepayers, I would remind you that we are not just talking about residential users, we are talking about industry and commerce. And I think that is extremely important to bear in mind.

Senator **Ford**. When you say $800 million, is that total cost or is that an annual cost to the ratepayer?

Ms. **Anderson**. That is an annual cost.

Senator **Ford**. Annual cost. So it would be $800 million per year, if you were required to install scrubbers.

Ms. **Anderson**. That is right.

Senator **Ford**. And what do you do with the sludge that comes from scrubbers? Have you determined what you do with all that?

Ms. **Anderson**. I will defer to my technical man, Mike Fielek.

Senator **Ford**. Do we put him on a barge? [Laughter.]

Mr. **Fielek**. Actually, we do not have any experience with scrubbers in Michigan. There is only one new plant that has scrubbers on it, and at this time all our plants are low-sulfur coal. No scrubbers.

Senator **Ford**. If you approve scrubbers, there has to be some way to remove the sludge or some way to contain it.

Have you not looked at that?

Mr. **Fielek**. The utility proposals for plants that have not been constructed, there would be landfill.

Senator **Ford**. Landfill?

Mr. **Fielek**. Yes.

Senator **Ford**. That is interesting. Yes, was that Will Rogers who said that land is something we are not making more of?

Let me ask you one final question. My time is moving on here. You seem to be very concerned in your testimony about the prudency presumption in S. 879, which would apply in state proceedings.

Would it be helpful if some distinction was made between prudency of a decision to embark on a clean coal technology and the prudency in implementation and managing that decision?

Ms. **Anderson**. Well, I think any dichotomy of that nature would be useful.

We certainly would want to know, as I heard the Chair explain, there was certainly more in his explanation of what that would consist of than is present in the bill. So we would like to know more about that.

But I would not be able to respond as to whether or not that would make a direct and abiding difference in terms of the reception of this concept by regulators generally. That is something that I would have to discuss with them in much more detail.

Senator **Ford**. But is it your opinion that they should be examined separately?

Ms. **Anderson**. Yes, I think it is important that it be an ongoing process, that you be able to make those determinations along the way, and as has been the case in these other experiences we have had to make after-the-fact judgments. And that has been unfortunate.

Senator **Ford**. I understand where you are coming from as it relates to having input and being a part of.

I need to know, I am a co-sponsor and very active supporter of S. 879, as you probably know, but I have an open mind. I want this to work. I think it is the best for the country. I think it is best for our natural resources.

I think it is far better for our ratepayers than anything else we can do. The cost in my state if we went to scrubbers would be $700 million. And we are the largest coal-producing state in the nation. That is annually.

So between you and I, just two states would pay $1.5 billion additional a year if we are forced to put in scrubbers. And yet you are going to have a landfill for the sludge and I am not sure you have that all worked out yet.

So where do you want to have input? How long do you want the input? And where do we draw the line?

Where you make the decision on a rate case, we have to pass a piece of legislation. In our legislation we can include certain things or we can exclude it, as you do in your rate case.

Where do you enter as commissioners and where do you depart from the scene? Because if you are in this bill, then you have to make a decision. I do not know if that is double jeopardy or not.

Ms. **Anderson**. Well, I think you are absolutely right. We are not the decision-makers here.

We would like to lead up to the process whereby you have sufficient information on which to base a sound judgment. The administration's proposal calls for an innovative technology whatever, advisory panel.

We are suggesting that we ought to be a part of that panel in order to review the projects that are put forth, that we ought to have some input so that whoever makes the ultimate decision will have the regulatory perspective in full view and in mind as those decisions are made.

We are not saying that we ought to be the decision-makers. We are simply saying that we get called frequently here and elsewhere, regulatory impediments.

And we are trying to come away from that perception and that role and to play a very active role as a partner in this process and to be able to provide information that will enable you to make the decision at whatever juncture you feel it is important.

Senator FORD. Do you not, in making your decisions, very often plow new ground?

Ms. ANDERSON. Yes.

Senator FORD. Well, we are plowing new ground here, so I think we should understand the position of both of us here. And I thank you very much, both of you. You have been very good.

The CHAIRMAN. Thank you, Mr. Warner and Ms. Anderson. You have been very helpful.

Next we will hear from Mr. David Hawkins, senior attorney from the Natural Resources Defense Council on behalf of the National Clean Air Coalition.

STATEMENT OF DAVID G. HAWKINS, NATURAL RESOURCES DEFENSE COUNCIL, ON BEHALF OF THE NATIONAL CLEAN AIR COALITION

Mr. HAWKINS. Thank you, Mr. Chairman.

The CHAIRMAN. Good to have you, Mr. Hawkins.

Mr. HAWKINS. We do appreciate the opportunity, we the coalition, and I personally appreciate the opportunity to be here to testify today on S. 879 and other legislative proposals for multi-billion dollar clean coal demonstration programs.

I would like to summarize my written statement. At the outset I would like to state the coalition's view on this legislation, and it is that we oppose proposals to subsidize industrial coal-related research and development programs in the name of clean coal, unless these proposals are integrated with a new law that requires a program to reduce emissions in order to control the very serious problems caused by acid rain.

We believe there is no need to spend billions of dollars of taxpayers' money to demonstrate emerging coal cleanup methods. Indeed we believe that proposals to subsidize these demonstrations in the absence of acid rain control legislation may actually produce delay in emission reductions and delay in the deployment of improved technology.

First I would like to discuss the relationship between clean coal demonstrations and acid rain control. Unfortunately, it appears that many supporters of a clean coal program are just using the program as another reason to oppose acid rain controls.

They make essentially three claims. First they claim that current control methods are unacceptable means to pursue an acid rain control program. Second, they claim that superior methods with wide potential applicability are on the verge of commercialization.

And third, they claim that the clean coal demonstration program will be sufficient to accelerate such commercialization, while that schedule's impending acid rain control bills will ensure that emerging technologies are ignored.

My written statement addresses each of these three claims. I would like to just summarize it.

On the first claim, the argument that we must wait for better control methods is not a new one. Twenty years ago opponents of emission control bills asked Congress to wait a few years so that flue gas scrubbers could be developed.

Well, these technologies have been developed and they have been refined. But once again, Congress is being asked to wait for methods that are not yet here.

Opponents of acid rain controls also charge that today's technologies are too expensive. However, their assessments exaggerate the true costs of these technologies.

It is easy to double or triple control cost estimates by using high capital cost assumptions for FGD systems, applying high capital charge rates and other misleading accounting techniques and by assuming installation of far more FGD capacity than would be required to achieve required reductions under various bills.

I would also like to mention this year, as I did in testimony a year ago to this committee, the acid rain control program now being implemented in West Germany.

Under legislation that was enacted in 1983, every large coal-fired plant in West Germany that will operate past 1993 is being required to install and operate a high-efficiency FGD system by the beginning of 1988.

That is less than 7 months from today, West Germany will have fully implemented a wholesale FGD retrofit program in the space of time that we in the United States have been debating the question.

Scores of these systems have been ordered and are now under construction, and cost information from West Germany shows that capital costs of about $100 per kilowatt are typical for a 350 megawatt retrofit with even lower costs for larger plants.

Now we neither advocate nor oppose a wholesale FGD program, or any other technology specific solution to acid rain.

However, West Germany, which like the United States depends heavily on domestic coal and competes vigorously in international trade, is demonstrating that such a strategy is technically and economically feasible and can be implemented much more rapidly than the schedule contained in any bills now pending in Congress.

The CHAIRMAN. Let me interrupt you at that point to ask, how does West Germany just order the utilities to do so?

Mr. HAWKINS. The West German parliament, in 1983, adopted a piece of legislation that specified a reduction requirement, similar in some ways to our percentage reduction requirement that Senator Domenici was lamenting a little while ago, only it applies to existing plants.

It basically said, clean up or shut down. If you want to shut down this plant in 5 years, tell us that and we will exempt you from the program. But if you are going to keep operating that plant, you have got to clean it up.

The CHAIRMAN. No tax incentives. No subsidy.

Mr. **Hawkins**. There is no subsidy written in the legislation. Like a lot of the utilities in West Germany are operated by the lender, the state governments, and so they have opportunities of course to build in subsidies.

The **Chairman**. Well, they are operated by the state government?

Mr. **Hawkins**. A number of them are, yes.

The **Chairman**. Taxpayer subsidy?

Mr. **Hawkins**. They have the opportunity for that. Of course, the taxpayers and the ratepayers there are the same people.

The **Chairman**. They are in this country, I think, too.

Mr. **Hawkins**. Yes, they are.

With respect to applicability of clean coal technologies, the basic issue is applicability of technologies to existing plants, about 200 gigawatts of existing plants that were built in a 25 year period, spanning roughly 1950 to 1975.

These are the fairly new, high capacity, high sulfur coal, and exempt from new source performance standard plants. These are the plants whose emissions need to be reduced if we are going to attack the acid rain control program.

So the relevant question to ask about emerging technologies and their benefits for acid rain controls is, how many of these technologies suitable for retrofit application to these types of plants is the industry ready to go forward with?

My written statement describes several relevant responses. To summarize, industry does appear ready, based on responses to DOE solicitations, to demonstrate at least two retrofittable techniques, the sorbent injection technique, and the advanced combustors, that have not yet been commercially demonstrated.

Now what about the relationship of these demonstration schedules to acid rain control bill schedules? Well, there is no conflict between the pending acid rain control bills and the completion of the demonstrations that I have mentioned.

To the contrary, delaying passage of a new law will create incentives to reduce efforts to successfully prove out these additional technologies. The most relevant retrofittable technologies have demonstration schedules of 3 to 4 years.

Most of the acid rain control bills before Congress do not require reductions before the mid-1990s, thus allowing ample time for factoring in the results of these demonstrations.

Moreover, passage of acid rain control laws in this Congress will ensure that industry treats the potential for use of emerging controls as a serious option.

Confronted with the need to plan for a real emission reduction program, the industry will have a genuine incentive to devote resources required to provide prompt answers to reduce any technical risks associated with emerging technologies.

In contrast, if acid rain control schedules were linked to some unspecified level of proof that new technologies were demonstrated, well then the industry would have an enormous incentive to delay such demonstrations and to characterize the results of any demonstrations as not sufficiently conclusive.

In other words, if they say they have got the technical answer to the problem, and that means Congress enacts a control law, then they are going to at all costs avoid saying they have the technical answer to the problem.

The second topic I would like to briefly address is the relationship of DOE's clean coal program to the Special Envoys Report.

Unfortunately, our government's implementation of the clean coal program to date, we believe, shows that in the absence of a statutory emission reduction program, neither the government nor industry will focus available subsidies on technologies that would most usefully complement existing control methods in an acid rain control program.

Of the nine projects selected by DOE last August, only two, arguably three, meet the criteria for the commercial and retrofittability of the Envoy Report.

More importantly, according to a Congressional Research Study, the total subsidy allocated to these projects amounts to only $23.6 million, which is only 6 percent of the total $400 million subsidy which was committed in round 1 of the program.

In addition, the procedures employed by DOE in carrying out the program have frustrated efforts to maximize the environmental benefits of the subsidies that have been committed.

We have tried, since the inception of the program over a year ago, to acquire information from DOE on the projected emission reduction effects of each of the proposed projects so that we could provide Congress with an analysis that might assist Congress in its oversight of DOE choices.

However, all of our requests to DOE have been denied, and DOE's stated reason for concealment is a sweeping claim that all information in a project proposal is business confidential information.

Moreover, DOE has even refused to provide a copy of its own environmental impact assessments of the nine selected projects, claiming that these assessments are part of its deliberative process.

In addition to secrecy, the DOE process has failed to conform to the process called for in the Special Envoys Report. The report intended that projects be selected by a panel that includes representatives of the U.S. EPA and the Canadian government.

This is not an advisory panel. The report clearly states, that is a panel to actually do the selections. Well, DOE claims that some of its first nine selections meet the criteria of the Envoys Report. The selections were made unilaterally by DOE, not by the panel called for in the Envoys Report.

Finally, the pace of DOE's actions is quite slow. The appropriations bill mandated that DOE select projects by August of 1986. But it did not set a deadline for completing the binding agreements.

And as a result only three of the nine projects selected have actually had binding agreements completed. So these major problems with DOE's implementation lead us to recommend that if additional monies are indeed appropriated, that EPA ought to be the responsible agency, not DOE, for undertaking these demonstrations and funding of them.

In conclusion, we urge this committee to not act on proposals for additional clean coal subsidies except in concert with action by the

Environment and Public Works Committee on long delayed acid rain control legislation. Thank you very much.

[The prepared statement of Mr. Hawkins follows:]

Natural Resources
Defense Council

1350 New York Ave., N.W.
Washington, DC 20005
202 783-7800

Testimony by

David G. Hawkins

NATURAL RESOURCES DEFENSE COUNCIL

on behalf of the

NATIONAL CLEAN AIR COALITION

before the

Committee on Energy and Natural Resources
U.S. Senate

May 18, 1987

Thank you for the opportunity to testify on S. 879 and other legislative proposals for a multibillion dollar "clean coal" demonstration program.

Let me state the National Clean Air Coalition's view at the outset of my remarks. We oppose proposals to subsidize industrial coal-related research and development programs in the name of "clean coal" unless these proposals are integrated with a new law requiring a program of adequate emission reductions to remedy the serious problems caused by acid rain. We believe there is no need to spend billions of taxpayers' dollars to demonstrate emerging coal cleanup methods. Indeed, we submit that proposals to subsidize coal pollution control demonstrations in the absence of acid rain control legislation will produce

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delay in emission reductions and delay in the deployment of improved technologies.

Over two decades of research have produced a range of fully demonstrated methods to reduce acid rain precursor emissions. Today's available control methods are adequate to achieve in a reliable and affordable fashion, any level of emission reductions proposed in this or the last several Congresses. The additional "clean coal" demonstration projects now underway may prove out several useful methods to complement the current mix of control methods. However, a "clean coal" demonstration program is not, as claimed by acid rain control opponents, reason to delay enactment of a law requiring emission reductions on a prompt schedule.

I. Relationship Between "Clean Coal" Demonstrations and Acid Rain Control

Since 1980 opponents of acid rain control have trotted out a series of arguments against a new law: there is no problem; we don't understand the cause of the problem; somebody else causes the problem; we don't know how to fix the problem or we can't afford to do it. As the weaknesses of these arguments have been exposed, control opponents have turned to what is traditionally the last weapon in their arsenal of delay: they predict a vastly superior solution to the problem just over the horizon and urge Congress to wait until it arrives.

Those who argue we should "wait for clean coal technologies" base their case on several claims that do not withstand analysis:

First, they claim that current control methods are unacceptable means to pursue a control program;

Second, they claim that superior methods with wide potential applicability are on the verge of commercialization; and

Third, they claim that the "clean coal" grant program will be sufficient to accelerate such commercialization, while the schedules in pending control bills will insure that emerging technologies are ignored.

I would like to address these claims in turn.

1. Current control methods can do the job.

The argument that we must wait for better control methods is not a new one. Essentially the same argument was made twenty years ago to the Senate by the same industries that are now most vigorously opposing acid rain controls. Then, as now, the issue was whether the federal government should require a major reduction in emissions from the electric utility and other major industries. The utility and coal industries argued then for delay and promoted tall stacks as the "solution that buys us the time required to carry out the research that may one day give us still better solutions."[1] Coal industry witnesses pointed to the emerging technology of flue gas desulfurization (FGD) as a method that, with 3-5 years of additional development work, could be used to attack the coal sulfur problem.[3]

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[1] "Air Pollution - 1967," Hearings before the Subcommittee on Air and Water Pollution, Committee on Public Works, U.S. Senate, 90th Cong., 1st Sess. (1967) at 2046. (Statement of Philip Sporn, American Electric Power Co., Inc.).

Well, FGD systems and other methods were developed and improved through the 1970s and are now proven, reliable means of controlling both new and existing plants. However, now that we have been through two decades of development and refinement of FGD and other control systems, these "emerging technologies" of twenty years ago are derided, and our attention is once more directed to methods that have not yet arrived.

Today's proven utility sulfur dioxide (SO_2) control technologies include third-generation "wet" FGD systems ("scrubbers"), regenerable FGD systems, spray dryers, atmospheric fluidized bed combustion (AFBC), coal cleaning, and fuel switching. Together, these techniques can achieve SO_2 reductions of 10-12 million tons, as called for in pending control legislation. Proven methods for nitrogen oxides (NOx) control include low NO_x burners, other combustion modifications, AFBC and several catalytic and non-catalytic flue gas cleanup techniques discussed at earlier hearings this year before the Senate Environment and Public Works Committee.

Opponents of acid rain controls charge that today's technologies are too expensive. However, their assessments exaggerate the true costs of these technologies. By using high capital cost assumptions for FGD systems, applying high capital charge rates and other misleading accounting techniques, and by assuming installation of far more FGD capacity than would be required to achieve required reductions, analysts have been able to generate very high cost estimates. An April 1986 Congressional Research Service staff critique of the Edison Electric Institute's analysis of H.R. 4567 shows that such techniques can double or triple estimated control costs.[3]

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[3] Id. at 2023, 2041, 2442.

For example, most government and industry studies have assumed FGD capital costs of $200-250 per kilowatt or higher. However, these estimates are based on engineering designs that rely on large amounts of spare scrubber module capacity and do not use additives to improve scrubber efficiency. Based on actual installation experience of recent U.S. FGD systems, a cost of $150 or less per kilowatt is appropriate.[4] In addition, even the Electric Power Research Institute's (EPRI) latest cost estimates for a new 500 mw high-sulfur coal FGD system with additives has dropped to $129 per kilowatt.[5] Since this EPRI figure contains significant spare scrubber capacity and very large allowances for "contingencies," it should be regarded as a high-side estimate.

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[3] CRS Staff Report, "Estimating Acid Rain Control Costs: Illustrative Problems from the Recent EEI-TBS Study of H.R. 4567," April 29, 1986.

[4] See Peabody Process Systems, "Acid Deposition Control: Economical Retrofit of Wet Scrubbers to Coal Fired Boilers," March 1986, at p. 6. Reprinted at "Clean Coal Technology Development and Strategies for Acid Rain Control," Hearings before the Senate Committee on Energy and Natural Resources, 99th Cong., 2d Sess., June 1986 at 588-607. (Hereinafter "Clean Coal Hearings").

[5] EPRI, Economic Evaluation of FGD Systems, Vol. 5, October 1986 at page 7-35 (Dec. 1982 dollars).

I would also like to mention this year, as I did in testimony a year ago to this Committee, the acid rain control program now being implemented in West Germany. Under legislation enacted in 1983, every large coal-fired plant in West Germany which will operate past 1993 is being required to install and operate a high-efficiency FGD system by the beginning of 1988. Thus, less than seven months from today, West Germany will have fully implemented a wholesale FGD retrofit program. Scores of these systems have been ordered and are now under construction.[6] Cost information from West Germany shows capital costs of about $100 per kilowatt for a typical 350 megawatt retrofit, with lower unit costs for larger plants.[7]

The National Clean Air Coalition neither advocates nor opposes a wholesale FGD retrofit program or any other technology-specific solution to acid rain. However, West Germany, which like the United States depends heavily on domestic coal and competes vigorously in international trade, is demonstrating that such a strategy is technically and economically feasible and can be implemented more rapidly than the schedule contained in any bills now pending in Congress.

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[6] See Wm. Ellison, "Survey Report and Assessment of Utility Flue Gas Desulfurization Systems Installation in Europe," Ninth EPA/EPRI Symposium on Flue Gas Desulfurization, Cincinnati, Ohio, June 4-7, 1985. Tables 1-4 of the Ellison paper summarize Germany's control requirements and FGD systems ordered as of year-end 1984. Reprinted at Clean Coal Hearings, supra, n.4 at 608-609.

[7] Bernd Scharer and Norbert Haug, "The cost of flue gas desulphurization and denitrification in the Federal Republic of Germany," Fourth Seminar on the Control of Sulfur and Nitrogen Oxides from Stationary Sources, Graz, Austria, May 12-16, 1986.

The reductions required by the pending bills would not require universal use of FGD systems, but rather, could be complied with by using a mixture of available controls, including conventional FGDs, regenerable FGDs, spray dryer systems, repowering with AFBC, coal cleaning, continued use of low sulfur fuels and, to the extent Congress decides is appropriate, fuel switching.

2. Applicability of "Clean Coal Technologies."

Advocates of "clean coal" technologies can describe a long list of concepts in varying stages of development but most of these concepts will apply primarily to new plant or repowering projects. To control acid rain we must reduce emissions from the roughly 200 gigawatts of pre-NSPS coal and oil utility plants. Most of these plants have operated for less than half of their estimated useful life and significant reductions due to retirement cannot be expected until the end of the first quarter of the next century. Life extension programs could push reductions from retirements even further into the future.

The relevant question to ask about emerging technologies and acid rain control programs is, thus, how many technologies suitable for retrofit application is the industry today ready and willing to attempt to demonstrate commercially? The answer to this question can be gleaned from the submissions made to the

Department of Energy (DOE) in response to DOE's February 1986 $400 million "clean coal" program solicitation and, more speculatively, from DOE's November 1986 "retrofit" program announcement.

In my testimony last year I discussed several proposals submitted for the "first round" DOE program that appeared to represent commercial-scale demonstrations of retrofit technologies with potentially wide application. These proposals included furnace sorbent injection demonstrations by Babcock & Wilcox (B&W) and the Energy and Environmental Research Corp. (EER), as well as a combination proposal from TRW, Inc. to demonstrate, at separate sites, components of an integrated furnace sorbent injection and spray dryer system. The B&W proposal would support two years of additional testing of the sorbent injection demonstration system now being installed at Ohio Edison's Edgewater plant. The B&W and EER proposals were selected by DOE in August 1986, while the TRW proposal was not selected.

In addition to these three proposals, a submission from TVA proposed to demonstrate a spray dryer system on medium and high sulfur coals at its Shawnee plant. It is not clear that the TVA demo is needed to commercialize application of spray dryer technology to eastern coals, given the experience already gathered at other utility and industrial plants. EPA's 1986 proposed NSPS for industrial boilers regards spray dryer systems as demonstrated conventional technology capable of achieving a 90% reduction in SO_2 on any type of coal.

The fifth commercial-scale retrofit proposal was submitted by Recovery Systems, Ltd. for a regenerable FGD system that produces fertilizer.

Another advanced FGD system with retrofit potential was proposed by NOXSO Corp. However, this proposal is limited to a pilot scale of 5 megawatts electric of flue gas. This represented a scaling back from NOXSO's February 1985 submittal, which proposed a 100 megawatt commercial demonstration of this technology, contingent on locating a host utility.

In addition to the above proposals, nine proposals for fluidized bed boilers (seven atmospheric and two pressurized) were submitted. While atmospheric FBC units appear to be an attractive alternative for smaller, older units undergoing repowering for life extension programs, FBC is unlikely to be an economically competitive option for the many larger pre-NSPS units built between 1960 and the mid-1970s. Moreover, at least three utilities have already independently committed to commercial construction of AFBC units, indicating that the industry itself regards this technology as demonstrated.

Another potential retrofit technology is the so-called "advanced combustor." A small scale demonstration proposal for an industrial boiler was selected by DOE in the "first round" program.

The Congressional Research Service analysis of the DOE "first round" selections concludes that only the B&W, EER and Coal Tech proposals have significant retrofit potential.[8]

DOE's November 1986 program announcement has produced 139 "Statements of Interest."[9] Since the DOE announcement stated that no monies were available to fund any submissions received, the submissions do not represent formal commitments by the proposers to carry out any of the described projects. When and if DOE actually publishes a funded program announcement fewer responses may result. (A similar, unfunded DOE announcement in 1985 elicited 175 responses, while the follow-up, funded February 1986 announcement resulted in only 51 proposals.)

Nevertheless, the most recent submissions do provide some useful information on potential retrofit methods. There are a few proposals for full utility-sized demonstration of the "advanced combustor" technology that DOE has committed to fund at the smaller industrial boiler scale. There are a number of additional furnace sorbent injection proposals and several duct sorbent injection proposals. In addition there are several proposals for refinements to conventional FGD systems.

In short, based on the responses to the DOE program announcements, industry appears prepared to construct commercial-scale versions of several technologies (sorbent injection systems, spray dryers for higher sulfur coals, "advanced combustors" and refined FGD systems) that may have broad applicability to the retrofit market. While use of these systems would complement current conventional controls (in our view, spray dryers and several of the refined FGD systems are already demonstrated technology), there is no basis for a claim that delaying acid rain controls is either necessary or sufficient to promote rapid application of these methods.

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[8] See CRS, "Acid Rain, DOE's Clean Coal Technology Program and the Lewis-Davis Report: Squaring A Circle?," January 21, 1987.

[9] See March 6, 1987 DOE "Summary Report to Congress on Emerging Coal Technologies Capable of Retrofitting, Repowering or Modernizing Existing Facilities."

3. Control Program Delays Will Delay Demonstrations of Emerging Technologies.

There is no conflict between pending acid rain control bills and completion of the demonstrations of the retrofittable technologies discussed above. To the contrary, delaying passage of a new law will create incentives to reduce efforts to successfully prove out these additional control methods.

Two of the major systems receiving industry attention, sorbent injection and spray drying, have already received limited commercial demonstration. Additional work can be completed in two to four years with sufficient industry interest so that results can be made available prior to even the earliest mandatory date for achieving emission reductions in most pending control bills. The B&W and EER furnace sorbent injection projects selected by DOE will have fully evaluated operational results completed within 43 and 48 months respectively and will begin operation well before that date. The Coal Tech advanced combustor will be demonstrated in 27 months; similar utility-scale advanced combustor proposals just submitted to DOE have 2-3 year schedules for reporting operational results.[18]

Under S. 321, Senator Mitchell's acid rain control bill, reductions are not required for sources using control technologies until 1996. States must adopt emission limits within two years of enactment. Therefore, sources that wish to preserve an option for use of an "emerging" technology would make a conservative estimate of the technology's emission reduction potential prior to that time and seek a source-specific emission limit that would be achievable, given the technology's assumed reduction potential. Sources needing to control by 1996 would probably need to make a construction decision by 1993-94. Based on the information presented in the DOE abstracts, results from the furnace sorbent injection, duct sorbent injection, advanced combustor, refined FGD and spray dryer demos will be available by 1991 or earlier.

Passage of acid rain control laws in this Congress will insure that industry treats the potential for use of emerging controls as a serious matter. Confronted with the need to plan for a real emission reduction program, the industry will have a genuine incentive to pool the resources required to provide prompt answers to reduce any technical risks associated with emerging technologies.

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[18] See, e.g., DOE March 6, 1987 Summary Report at 134-137 (TRW and Ohio Edison combustor proposals).

In contrast, if acid rain control schedules were linked to some unspecified level of proof that new technologies were demonstrated, the industry would have an enormous incentive to delay such demonstrations and to characterize the results of any demonstrations as not sufficiently conclusive. All the while, damages caused by acid rain would continue.

Mr. Chairman, the worst possible result from both a fiscal and an environmental standpoint would be to spend billions of taxpayers' dollars on a program to prove that emerging technology does not work. Yet this would be the most likely outcome of any "clean coal" demonstration program that is linked to a delay in control requirements pending "adequate" results. Under such an approach, industry would know that "success" would bring on new regulation while "failure" would buy more time. Taxpayers cannot be dismissed as cynics if they assume that, faced with such incentives, industry would be tempted to spend as much time and as much taxpayers' money as they could get away with on such demonstrations.

II. Relationship of the DOE Clean Coal Program to the Special Envoys Report

The January 1986 Special Envoys Report recommended a five-year, $5 billion control technology commercial demonstration program, with half of the funding from the federal government and the other half from industry. On March 19, 1986 President Reagan stated "I fully endorse the report." An accompanying Press Statement went on to state "the Administration will seek to provide in the future the funding recommended in the Joint Report." After exactly a full year's delay and cries of anguish from the Canadian Prime Minister, President Reagan on March 19, 1987, said the Administration would request the money promised in the 1986 announcement.

Our government's implementation of the clean coal program to date shows that in the absence of a statutory emission reduction program neither the government nor industry will focus available subsidies on technologies that would most usefully complement existing control methods in an acid rain control program. The central objectives of the Envoy Report were to expand the menu of cleanup methods for existing commercial-scale utility plants and to achieve a near-term reduction in emissions. Last August DOE selected nine projects that will consume approximately $400 million in subsidies. However, only two, arguably three, of the nine projects selected by DOE last August in "round one" of the clean coal program meet the commercial and retrofit criteria of the Envoys Report. More importantly, according to the CRS analysis, the total subsidy allocated to these projects, amounts to only $23.6 million, just 6% of the total subsidies committed in "round one" of the program.[11]

In addition, the procedures employed by DOE in carrying out the program have frustrated efforts to maximize the environmental benefits of the subsidies that have been committed. One of the requirements of the 1985 appropriation establishing the "round one" program was for a thirty-day waiting period between DOE selection of a project and the signing of a binding agreement. The purpose of this waiting period was to give Congress an opportunity to evaluate the wisdom of DOE's selections. We have sought since the inception of the program to acquire information on the projected emission reduction effects of the proposed projects so that we might provide Congress with an analysis during the prescribed waiting period.

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[11] See January 1987 CRS report, supra, at 26.

Over the past year we have filed two Freedom of Information requests and two administrative appeals seeking information on the projected emissions from each of the projects reviewed or selected by DOE. All of these requests have been denied by DOE. DOE's reason for concealment is a sweeping claim that all information in a project proposal is business confidential information. While there is no basis in logic or in law for such a claim, DOE's posture has nonetheless prevented us from acquiring the information as a practical matter.

Moreover, DOE even has refused to provide a copy of its own environmental impact assessments of the nine selected projects, claiming that these assessments are part of its "deliberative process." While we hope such assessments were in fact considered by DOE, it frustrates a fundamental purpose of the National Environmental Policy Act for DOE to keep these assessments secret during a period when Congress and the public may wish to learn more about the projects in question and the alternatives not selected.

In addition to secrecy, the DOE process has failed to conform to the process called for in the Special Envoys Report.

The Report intended that projects be selected by a panel that includes representatives of the U.S. EPA and the Canadian Government. While DOE claims that some of its first nine selections meet the criteria of the Envoys Report, these selections were made unilaterally by DOE, not by the panel called for in the Envoys Report.

Finally, the pace of DOE's actions calls into question its commitment to promptly demonstrate clean coal technologies. The appropriations bill mandated that DOE select projects by August 1986 but did not set a deadline for completing the binding agreements necessary to actually implement the projects. As a result, DOE has completed agreements for only three of the nine projects since its selection announcement, with the third agreement reached only last week.

These major problems with DOE's implementation of the program lead us to conclude that if any additional moneys are appropriated, they should be administered by EPA and not by DOE.

In conclusion, we urge this Committee to not act on proposals for additional clean coal subsidies except in concert with action by the Environment and Public Works Committee on long-delayed acid rain control legislation.

Thank you. I'll be happy to answer your questions.

The CHAIRMAN. Thank you very much, Mr. Hawkins. First of all, let me say, I do not see this bill and acid rain to be mutually exclusive but rather to be mutually reinforcing.

I mean, I think we ought to do all we can, and clearly this helps get the air cleaner. Whether it does the whole job or not is another question. Whether it does as much as it should, but I see no inconsistency at all between this bill and other actions that may or may not be taken.

On the question of acid rain legislation, I am not at all an expert, in fact I do not know a great deal about the details of the legislation.

But I recall that at the time we did the oil backout bill, we identified certain named power plants and provided what was a taxpayer subsidy at that time, partially shared by taxpayer funds, partially shared by the utilities, to clean up those plants with an order to close them.

Now the advantage we saw at that time was that certain plants were greater offenders than others, that recognizing that whether it is taxpayers' dollars or ratepayers' dollars, it all comes out of a common, it is all money, and that we could maximize the money to be spent by focusing in on individual plants.

Now it is my understanding that the Mitchell bill does not take that approach.

Mr. HAWKINS. That is correct.

The CHAIRMAN. Tell me why that approach is not a good one.

Mr. HAWKINS. Well, it is not necessarily a bad one. There are various options.

The oil backout bill that you referred to, Mr. Chairman, did not require pollution control equipment to be applied as a part of the oil to coal conversion, but it did name specific oil and gas burning plants.

Since 1980, H.R. 3400 in the other body did identify the 50 largest and dirtiest coal-fired plants and did require those plants to achieve the emission reductions by a technological means, rather than fuel-switching.

One of the reasons for that particular approach was a view that if those plants switched fuel, then some high sulfur coal producing districts, such as those represented by Senator Ford and others, might suffer undue, adverse economic and social effects. And this was an attempt to mitigate that.

The naming of specific plants is always a difficult thing to do. The Clean Air Coalition does not feel that that is an essential element of an acid rain control bill, and that is why we are happily willing to support Senator Mitchell's bill that does not do that.

The CHAIRMAN. Well, as I recall, and I do not want to get on this too much, except it is on the broad subject and my first time to have a real expert here where I can talk about this question.

As I recall in those days, the location of a plant has a great deal to do with the difficulty which its emissions, the problem that it solves. I mean, if it is located on the ocean with prevailing winds that go out to sea, there is not a particular problem.

So why should we not identify specific plants and, if we are going to require them by whatever means, to reduce that emission, why should we not identify specific ones and pay for it with taxpayers 'dollars?

As opposed to, maybe Senator Ford's plants do not cause as much problem. They would be a lower priority, but we could make them pay for somebody else's cleanup.

Mr. HAWKINS. Well, we believe that at a minimum the bills should allocate emission reductions to the states, and identify for each state how much of an emission reduction, as part of an overall national share of an emission reduction, be achieved in that state.

We do not think that that should be left up to EPA, for the very pragmatic reason that EPA's decision-making process has become so cumbersome, so controversial, that it is virtually impossible to get a decision out of that agency on any matter of controversy in less than a decade.

And that is particularly true when it involves making decisions that in one state's eyes appear to make it a winner, and in another state's eyes appear to make the state a loser.

The Federal government has never been particularly good, the Executive branch, at deciding which state is going to be a winner and which state is going to be a loser. They like to try to find ways that they can claim that everybody is a winner.

The CHAIRMAN. There are those who suggest that the way an acid rain program or pollution cleanup program should be structured is by fee on pollution, a graduated fee that starts off very, very low and rises.

That would have two effects. It would encourage the cleanup, it would provide the funds for the cleanup, it would also help in making public utility commissions approve cleaner combustion technologies that might cost a little more but when added to the fee would help in that manner.

What is wrong with that? Why should we not do that, or should we do that?

Mr. HAWKINS. The Clean Air Coalition could support bills that contained that mechanism as well. The principle criteria that the Clean Air Coalition uses to judge acid rain control bills is the amount of emission reduction that the bill provides, and the amount of time that the bill allows for achieving those emission reductions.

Basically, our view is that we need to get reductions within a decade and we need to get reductions on the order of 12 million tons of sulfur dioxide and several million tons of nitrogen oxides.

We are not asking for reductions tomorrow, or next year. We are asking for reductions over a 10 year time frame.

The CHAIRMAN. Thank you very much, Mr. Hawkins.

Senator Ford.

Senator FORD. You are talking about reductions, I will just start right there. I have some other things I want to talk to you about.

But when you talk about reductions, say a state has done an excellent job. It has been reducing its problem. Is there any chance for credits, or do they get saddled immediately with the additional reduction, which makes it quite harsh?

Mr. HAWKINS. Virtually all the bills, Senator Ford, that have been introduced in Congress give states credit for having reduced their emissions.

Senator **Ford**. How much credit? From what date?

Mr. **Hawkins**. They give credit based on what the emission reductions, the emission reductions are allocated based typically on what a state's emission rates were in 1980.

And any reductions prior to 1980 are thereby credited, and indeed any reduction——

Senator **Ford**. How much credit do we get prior to 1980?

Mr. **Hawkins**. Full credit for the reductions.

Senator **Ford**. Full credit.

Mr. **Hawkins**. Yes.

Senator **Ford**. Full credit.

Mr. **Hawkins**. And any reductions after——

Senator **Ford**. Before 1980.

Mr. **Hawkins**. And in addition, reductions after 1980 are achieved as well.

Basically, the allocation mechanism is one that says, if you are a state that is already clean, based on how many pounds of sulfur dioxide you put into the air per kilowatt of electricity that you generate, if you are already clean then the legislation asks you to do less to start with.

Senator **Ford**. I wanted to get you on the record saying that you get credit before 1980, and you said that we would get full credit before 1980. Am I correct?

Mr. **Hawkins**. You get credit for reductions both before and after 1980.

Senator **Ford**. But full credit prior to 1980.

Mr. **Hawkins**. Yes.

Senator **Ford**. OK. In your statement you argue that opponents of acid rain controls believe that current technologies cannot control emissions adequately.

I do not think that there is any question that these technologies can control the power plant emissions. It is only a question of cost.

You argue that others have overstated the cost per kilowatt of installing scrubbers. However, in your statement you note an EPRI figure showing scrubbers costs of only $129 per kw. Is that correct?

Mr. **Hawkins**. Yes. For a new plant.

Senator **Ford**. And yet you say that this should be considered as an outside estimate. But there is a strange footnote to your statement. That it is in 1982 dollars.

Mr. **Hawkins**. Yes.

Senator **Ford**. And I have had some staff members prepare an estimate and that it would be $150 in 1986 dollars.

Mr. **Hawkins**. Yes. In the same paragraph, Senator Ford, the $200 to $250 per kilowatt that I cited is also in 1982 dollars. So I was using consistent dollars throughout.

Senator **Ford**. All right. But 1982 and 1986, if you look at $129, you say that is the outside figure. Really, when somebody reads that they will think you are saying $129, when you really mean $150.

Mr. **Hawkins**. Well, in constant dollars, the point of this paragraph is to show that the numbers are substantially lower than all of the estimates that have been used in the government and industry studies.

Senator Ford. Regardless of what scrubbers cost, then, it would be helpful if we could have an apples and apples, get to that comparison in dollars of the same year.

Can you provide the Committee with a best estimate of the average cost of currently available FGD technology, which is scrubbers in current dollars? And also can you provide data on the range of costs, the most expensive and least expensive technology available?

Mr. Hawkins. Certainly, Senator Ford.

Senator Ford. Installed, now.

Mr. Hawkins. Yes. The costs of systems that would be ordered today, as opposed to the systems that have been ordered over the last 15 years?

Senator Ford. Yes. Yes.

Mr. Hawkins. I simply will provide the Committee with EPRI's own estimates, and I will escalate them to 1986 dollars.

Senator Ford. That will be fine, and I want the most expensive and least expensive technology available.

Mr. Hawkins. Well, I am sure that the most expensive is probably more a curiosity than anything else, but I will try to find out what it is.

Senator Ford. Well, are we not all curious? That is what we are trying to work out here in clean coal technologies, and if you are not curious about that you ought to be.

Mr. Hawkins. I assume that you are interested though in technologies that people are actually interested in buying.

Senator Ford. Yes. If people are not interested in buying, you are not going to sell it anyhow, unless you force it on them like Germany.

In your written testimony you stated that the Clean Air Coalition never advocates nor opposes a wholesale FGD program, or any other technology specific solution.

In recent testimony to the Environment Committee, Kurt Yaeger, an EPRI vice president, concluded, and I quote, "the inflexibility of proposed legislation intended to further reduce emissions tends to discourage the application of innovative clean coal technologies and limit the freedom of choice."

Specifically he was referring to bills which are very stringent and kick in in the very near future. He also asserts that this proposed legislation would increase the cost of compliance and delay the implementation of clean coal technologies which combine emissions controls and cost reductions.

Can you comment on that for the Committee?

Mr. Hawkins. Well, yes, Senator Ford. I just have to say that I believe that can only be viewed as a self-serving statement.

It is in the interests of the electric utility industry to make the argument that if you adopt emission control requirements that you are going to tie their hands and delay the improvements which would otherwise naturally occur.

This is a traditional argument that opponents of pollution control programs have always made. It is not a new argument. As I said, the utility industry made the same argument 20 years ago. They are making it again today.

Senator Ford. But do you believe that the bills that have been introduced are technology forcing?

That is, that they leave scrubber technology as the only way to meet the proposed emission reductions by the proposed deadline?

Mr. HAWKINS. There is one bill, which is Senator Stafford's bill, that does require plants after they reach age 30, to meet new source performance standards, which do require 70 to 90 percent removal of sulfur dioxide.

There are currently demonstrated two ways of doing that. One on large boilers, which would be flue gas desulfurization, and fluidized bed combustion, which is we believe commercial status for smaller boilers, that is, 300 megawatts or less.

Those two ways can meet it. But that applies only after the plant has exhausted what Congress believed was its useful life of 30 to 35 years.

Senator FORD. So what you are saying here is that if the costs of installing a scrubber, and we heard testimony earlier here from EPA I think it was, that we have got another 30 to 35 years out there of useful life of plants.

So what you are saying to me that if you go to the scubbers and they will extend that life much further, and you will have older plants that will tend in my opinion to give you more problems than if you would help us new technologies as it relates to clean coal.

Mr. HAWKINS. Well, Senator Ford——

Senator FORD. Of course, the fluidized bed combustion is a retrofit operation, and basically that is what we have been talking about here this afternoon.

Mr. HAWKINS. Retrofit or repowering. Yes, Senator Ford.

With respect to the life extension, most of the economic analyses will compare several options. Life extension expenditures, depending on how well maintained the plant has been in the past, may be roughly $300, $400, $500 a kilowatt.

That is contrasted with the expenditure of $1,200 to $1,600 per kilowatt for building a new plant with an FGD system. If you did not put the FGD system on the new plant, you might reduce that cost by about $200 a kilowatt. That is, bring it down to $1,000 to $1,400 a kilowatt.

So that is not going to make a difference. There still will be an incentive to extend the lives of these facilities.

One of the interesting analyses that was done for EPRI by Consumer Power, a utility in Commissioner Anderson's State of Michigan, indicated that it would still benefit the ratepayers to undertake a life extension program even if scrubbers were installed at 50 percent of Consumer Power's coal-fired capacity, and in addition other environmental upgrade equipment.

That the ratepayer would still be better off, even if scrubbers were installed as part of a life extension program.

Senator FORD. Then why are there not any scrubbers in Michigan?

Mr. HAWKINS. Because utilities will not make an expenditure for environmental cleanup unless they are required to do so, because it is not going to be better than no controls.

Senator FORD. Well, we just heard Ms. Anderson tell us that they are using low sulfur coal.

Mr. HAWKINS. Because of Michigan state regulations.

Senator FORD. Sure. So they apparently are meeting the standards.

Mr. HAWKINS. They are meeting the standards because they have been required to do so by law.

Senator FORD. They do not necessarily have to have scrubbers.

Mr. HAWKINS. As I say, the coalition does not take the position that an acid rain control bill has to require scrubbers. No, we do not take that position.

Senator FORD. What does it have to require?

Mr. HAWKINS. We believe that in order to solve the problem it has to require emission reductions by one means or another.

Senator FORD. By one means or another. By best known technology, is that what the language is, is it not?

Mr. HAWKINS. No, it is really short of best known technology.

Best known technology could achieve in excess of 90 percent emission control for sulfur dioxides. No bill is asking for 90 percent emission control.

Most of the bills are asking for a total of anywhere from 30 percent to 50 percent reductions in sulfur dioxide emissions. That is far from the best technology.

Senator FORD. It is my understanding, and this will be my last question, Mr. Chairman, I could go on with him for a while.

But it is my understanding that the technology used in West Germany that you keep alluding to is not necessarily applicable for the use of U.S. coal.

To this Senator that means that the cost estimates for reducing emissions from coal plants in Germany are something the United States should strive for, and not use as a basis of comparison of technologies with our coal.

Do you have any thoughts on that?

Mr. HAWKINS. Yes, Senator. With respect to sulfur dioxide, the technologies that they are using are the conventional, limestone scrubbers.

They are using processes manufactured by vendors who hold United States licenses. They are using technologies that are virtually identical in all respects with respect to sulfur oxide controls to equipment that the U.S. utility industry is ordering today for new power plants.

Senator FORD. Well, your information and mine, of course differ, and The Chairman said you are the expert and we are just learning.

So maybe, I will check on all that purchase of the German technology. Thank you, Mr. Chairman.

The CHAIRMAN. Thank you very much, Mr. Hawkins.

Mr. HAWKINS. Thank you very much.

The CHAIRMAN. Next we have Mr. Jack O'Leary, who is chairman and CEO of General Public Utilities Systems of Parsippany, New Jersey, on behalf of EEI, and also Ms. Ruth Gonze, who is assistant director for government relations of the American Public Power Association.

I would like to welcome Jack O'Leary back to the Committee. He spent a great deal of time in that position instructing us on many, many matters over a number of years, and Jack, it is good to see you back.

Mr. O'LEARY. Mr. Chairman, it is marvelous to be here, and I want to say that none of you have changed a bit. [Laughter.]

The CHAIRMAN. We are all younger. I am glad you brought Hazel with you as well. Please proceed, Jack.

By the way I am going to have to leave midway through your testimony because my staff unfortunately did not realize that such important witnesses were going to be here, and they arranged some 4:30 appointments. But I am going to be a little late for those, so please proceed.

STATEMENT OF JOHN F. O'LEARY, CHAIRMAN, GENERAL PUBLIC UTILITIES CORPORATION, ON BEHALF OF THE EDISON ELECTRIC INSTITUTE

Mr. O'LEARY. Mr. Chairman, at the rate that I am going to go through this, it will not be midway through, it will be very late in my testimony or perhaps after it.

Let me hit some points that occur to me in the course of the discussion this afternoon that might be useful to put before you and your fellow Members of the Committee.

First of all, I am representing EEI today, that has a very strong interest, of course, in the outcome of this bill.

In addition, I am here as the chairman of one of the member companies of EEI and one with a good many plants that are heavily dependent upon coal, and with major requirements developing in the future gives us a real stake in the outcome of the discussion before you.

First of all, Mr. Chairman, I think you have to bear in mind that we are talking about very large amounts of money in the subject matter before us here today. We are going to have to replace much of the generation that we currently have in this country over the course of the next 25 to 30 years.

We now have about 600 gigawatts of capacity, and we are going to have to add a substantial amount unless our efforts at conservation succeed better than they have been over the last several years.

We are now finding that the new requirements for electric power in this country are paralleling, roughly paralleling, the growth in economic activity, the GNP. There has been roughly a .8 to 1 relationship over the last several years.

In my part of the world we are running into peaks every summer, and unless something changes, and we hope it will, because we really do not want to add capacity, we suspect that we are going to see the requirement to augment that current 600 gigawatts or thereabouts at a rate of perhaps 2 percent a year.

That means that in the next 25 to 30 years we are going to have to add another, let us say, 400 gigawatts of capacity. So the total chore before us, then, is to catch up with the demise of a large share of our existing capacity, and to add a substantial block of new generating capacity over the next 20 to 25 to 30 years.

I would say that we are looking over that period of time of expenditures, investment on the part of the utility industry in this country, of on the order of $1 trillion to $2 trillion. Very, very large amounts of money.

We can do that with the current technology, which is before us. And I think most of us are agreed that that current technology is not up to the task.

Then the question comes up, why is the industry not finding new technology? I would like to contrast here the way the industry addressed this sort of a problem prior to the 1970s and the way it addresses it today.

My company, and the company of Mr. White, who is behind me here, who is chairman of American Electric Power, were leaders in innovation of this industry. There were a number of other companies that took the same role.

As a new technology began to be promising, we would incorporate it into our construction programs. At that time there was no particular question as to the recapture of that investment in rates.

Our rates were going down, by and large. The utility commissions were quite willing to see innovation, because they had seen the fruits of innovation in reduced rates over time.

And by and large the utility industry was capable of and was making very large investments in new technology. That simply is not the case today.

As we look over this horizon today, there is not to my knowledge a single instance in this country today where a large investment in innovative technology is being undertaken by an investor-owned and regulated utility.

Now there are a few examples where utilities are putting up a fair share of money, in combination with EPRI or in combination with the Department of Energy.

But there is not a single instance of which I am aware in which the pattern of the 1960s and 1950s and early 1970s is going forward. That is, large investments on the part of the utility, standing alone, aimed at reducing costs.

So long as that situation continues I think that our technology base here is going to be stagnant, and that means that that very large investment in replacement generation, and most likely in new generation, is going to have to take place at higher costs than need be the case.

The CHAIRMAN. That is because of this round of prudency hearings across the country?

Mr. O'LEARY. Well, that in part. There is another point that came to my mind.

Many utility commissions are finding that investments in plants that are now being abandoned for one reason or another were prudent. And they then permit a return of the investment over, let us say, a 10 year period.

They however uniformly do not permit a return on the investment. Now just putting it in numerical terms, if you put $100 million into a plant that is regarded by everyone in the system as having been an imprudent investment and because the situation changes and you prematurely abandon that plant, you are permitted to recover that $100 million over 10 years, $10 million a year, no interest on it.

And of course the 10 year period is critical because you are as the utility, are in effect foregoing the interest during that 10 year recover period.

The utility would like to recover it earlier. The ratepayers would like to recover it later. And the 10 year period has come out to be kind of a compromise, led by FERC.

But the principle here is that whether it is 5 or 10 or 15 years, the commissions have uniformly not permitted the utility to earn on that prudent investment.

So given that sort of a situation, the utilities have been very, very wary of making an investment, even though it is undeniably prudent and recognized as such, when they cannot recover their money in a timely fashion and earn on it.

The CHAIRMAN. Is there not also a perception, whether correct or not, among utilities that really prudent investments are being regarded as imprudent with the benefit of hindsight?

Mr. O'LEARY. Yes, I think that clearly is the case. There have been numerous hearings around the United States on this point.

I do not think that there is any question that utilities should not be permitted to recapture investments that are imprudent. But even going beyond that, Mr. Chairman, I think the prudency issue alone is not the regulatory issue that chills this.

It is the treatment after prudency has been developed that provides the chill. I just thought I would mention that, because you showed some interest in it earlier.

I have covered two points. The very large amounts of money that we are going to put here, the distinction between the old way of doing business, and the new way of business, new way of doing business.

I want to cover another point now with regard to the kind of investments that we had here. I served, Mr. Chairman, on a National Academy of Sciences review of the actions that were taken by the utility industry to clean up their air emissions in the mid-1970s.

At that time there were about 20 utilities in this country that had made very large investments on their own under the old rules, that they would make this investment hoping that it would turn out to be a good deal for their shareholders.

These added up probably to something on the order of $5 billion of total investment. We discussed the value of those investments with a number of those utilities.

The impression that I got from it is that, a) most of these were failures, you know it was very early on for that technology at that time, and b) most of those utilities, I can recall 18 out of the 20 or so, wished that they had not made that investment.

Now I am sure that that is with them today. They do not want to be pioneers. Some of the witnesses here today have talked about the successful course that we ran in getting from where we were in 1965 to where we are in 1985, with regard to FGD technology.

I want to tell you it has been enormously expensive, needlessly expensive, and you will not find the utility industry doing that again.

They simply can not see any way in which a given utility can recover its cost with that sort of a luck ratio and the sort of regulation that we have going today. If we want to move the technology, we are going to have to find some way to stimulate the investments.

Now let me finally talk about the regulatory issues before you. I think it is absolutely imperative that we address the relationships of these investments with the state regulators.

I could see that you were reaching for ways in which you could do that in the questioning that you had earlier. I really can not give you any advice with respect to specifics.

But first of all we have to recognize that they are absolutely crucial to this process. FERC only reaches perhaps 10 percent of the transactions that involved with this industry.

Ninety percent of them are regulated at the state level. It is crucial that we meet that in this legislation. I do not think it can be done coercively.

You have a very strong tradition of independence on the part of the state regulatory commissions, and they really much better than the Congress know their own particular circumstances.

And I think that they are going to have to be introduced into this with a great deal of care. As I say, I do not know exactly how to do it. But I think maybe you put your finger on it in one point that you were talking about earlier, and that is the oil withdrawal legislation.

In that particular instance, you will recall, we looked over, and I was with you in that look, we looked over a national problem. We were burning too much oil.

And we found that left to its own devices, the local communities, the states, where that oil, surplus oil or excess was being burnt, were going to continue to do that. The national interest might have been violated, but from the standpoint of local economics, it continued to make good sense to keep those plants running and burning oil.

And we said, well, the way to address is this first of all is to find a cost-effective means of withdrawal. That is to say, take your first $100 million and put that against the highest burners and so on down the line.

And secondly to realize that this is a national problem and one that must be addressed at the national level, and confers benefits across the country. And the oil backout legislation as you drafted it was the consequence of that.

In effect, we paid the people who owned the utilities a compensatory price to back out their oil and replace it with coal. At least that was the objective of that legislation.

I think you have to do very much the same thing in dealing with the states here. You have to recognize that there is not really a clean relationship between the national benefits and the benefits that can be captured by any state in making these investments.

[The prepared statement of Mr. O'Leary follows:]

HEARINGS ON S. 879,
THE CLEAN COAL TECHNOLOGY DEPLOYMENT ACT OF 1987

BEFORE THE

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE

U.S. SENATE

WRITTEN STATEMENT OF

JOHN F. O'LEARY

CHAIRMAN OF

GENERAL PUBLIC UTILITIES CORPORATION

APPEARING ON BEHALF OF THE

EDISON ELECTRIC INSTITUTE

MAY 18, 1987

I. INTRODUCTION

I am John F. O'Leary, Chairman and Chief Executive Officer of the General Public Utilities Corporation (GPU). GPU is an electric utility holding company with three operating companies, a nuclear generating company and a service company. Together, the GPU system companies provide electric service to more than 1.7 million customers in approximately half the land area of Pennsylvania and New Jersey.

I am testifying today on behalf of the Edison Electric Institute (EEI), the trade association of the investor-owned electric utility industry. I thank you for this opportunity to discuss EEI's views on S. 879, The Clean Coal Technology Deployment Act. This proposal represents an important effort by the federal government and the private sector to move new clean coal technologies into the marketplace and to remove barriers that currently impede their widespread use.

We want to commend you, Mr. Chairman, Senator Ford and other members of this Committee for the priority you have attached to this legislation. We also wish to commend Senator Robert Byrd who has been a leader in this effort and who introduced S. 879. We believe that your efforts will accelerate the use of these new clean coal technologies significantly.

The utility industry, after decades of research and development, is on the verge of utilizing an entirely new generation of coal based technologies. The technical progress in the research and development of these new technologies has been considerable. Many are now at a point where it is appropriate for them to be demonstrated on a commercial scale and then used in a number of applications to demonstrate their commercial worth. Current reserve margins in the electric utility industry create a "window of opportunity" during which we can act to bring these new technologies to maturity. Now is the time to build upon the advances we have made toward technologies which are better suited to the needs of utilities and utility customers. Currently available coal-fired technology simply does not match the potential of new technologies to meet the challenge of providing electricity at the lowest possible economic and environmental cost.

If the Congress and the Administration will assist in the successful demonstration and deployment of new clean coal technologies, the benefits could be substantial:

- coal-fired generation will be more cost effective and efficient, thereby benefitting the electric consumer;
- emissions from coal burning will be controlled more cost-effectively;
- domestic coal use will be sustained or increased, thereby stregthening the American coal industry; and

- new, more cost-effective coal utilization will enhance the U.S. economy, in general, thereby increasing our ability to compete in the world marketplace.

Finally, S. 879 provides strong evidence of a national commitment to encourage the use of new clean coal technologies by utilities and industrial generators that have varying needs in different parts of the country. It also provides the means for advancing an important goal of United States energy policy. For many years, the United States has sought a means to increase coal use and reaffirm domestic coal as a critical plank in our energy policy. The clean coal deployment program is clearly an excellent opportunity to move in this positive direction.

EEI is enthusiastic about the prospects of participating in a nationwide program that will permit increased use of coal as an acceptable fuel for increased generation, should the national interest demand it. The partnership between industry and government created by the clean coal program is the best means by which to achieve our shared objective of deploying clean coal technologies. We are pleased that the Congress and the Administration are moving in that direction.

II. EEI'S VIEWS ON S. 879

EEI has testified previously that there are substantial technical, economic and regulatory constraints to the widespread demonstration and deployment of these technologies. These impediments must be addressed if new clean coal technologies are to be widely used. S. 879 addresses these constraints in two ways:

- It provides financial assistance on a cost-sharing basis to reduce the risks associated with commercially immature technologies.
- It provides a specific set of regulatory changes which will help utilities to move forward rapidly to utilize these technologies.

We believe that a clean coal technology deployment program offers an appropriate approach to lessening or removing those technical, economic and regulatory constraints which will otherwise constrain the use of new technologies. EEI encourages the Committee to move expeditiously to reconcile differences among pending proposals and to develop a strong and effective clean coal deployment program.

III. THE NEED FOR GOVERNMENT PARTICIPATION

It is important to recognize that the demands placed upon the utility industry by those public bodies that regulate our activities are very high. In order for us to be able to charge our customers for technology that we develop and/or use on our system, we must prove to our regulators and our customers that the technology is capable of being used in the demanding utility environment. Because electric utility customers depend on us to provide a stable supply of power to them, the standards of performance of generating plants used to meet that obligation is very high.

Each technology must be taken through an extensive trial period to reduce technical risks. This is the principal objective of the current DOE clean coal demonstration program. Successful completion of phases I and II of this program should result in technical verification of a wide array of technology options.

However, even after the technical capabilities of a technology have been demonstrated, potential users still are confronted with a commercially immature technology. Several pioneer commercial facilities may have to be constructed and operated before industry and its regulators will consider these technologies to be acceptable options with acceptable commercial risks.

It is this need to "buy down the risks" of the first several commercial-sized facilities that the financial assistance and regulatory provisions in S. 879 are intended to meet. To ask an individual utility operating in a highly risk averse regulatory environment to accept such technical and financial risks alone will not maximize the results we can achieve from this program. For example, an individual regulatory commission may object to its ratepayers bearing all of the risks of developing a new technology when any benefits derived may accrue to ratepayers in other jurisdictions as well.

S. 879 also begins the process of identifying and attempting to remedy those disincentives to the demonstration and deployment of new clean coal technologies that currently exist in regulatory policy. Current regulatory policy is the principal source of economic risk which faces utilities that wish to utilize new technologies. It is important to recognize that the uncertainties in the regulatory arena may inhibit utilities from taking the steps necessary to bring these technologies into commercial use.

There is a strong inclination on the part of utilities and the commissions that regulate them to confine themselves to proven technologies when significant levels of investment are involved. In this risk averse climate, a utility could face a substantial or even total disallowance of its costs if an untried technology does not meet expectations. Also the potential that currently exists for retrospective prudency review means that utilities can be second guessed by their commissions long after substantial commitments and expenditures have been made. Even if the technology proves to be successful, entrepreneurial rates of return simply are not available to compensate for the risks taken. Rather, any return will be uncertain depending on whether, when, and to what extent public utility commissions treat these expenditures in determining their base revenues.

Regulatory changes, such as those proposed in S. 879, could provide for some assurance of a more reasonable recovery of costs for technologies which are proceeding through this demonstration and early deployment process and for utilities that incur the costs of perfecting new technologies. This is an important element of the program.

We also want to specifically note that the cooperation and participation of state regulatory commissions, which regulate close to 90% of utility rates, is important. We hope that this Committee and the Congress will encourage the states to adopt programs to achieve the national objective of moving these new technologies into the marketplace. This can be done, we believe, by the federal government, working with the governors, state energy officers and the public utility commissioners, to find the means of putting incentives in place that will encourage clean coal technology utilization in any given state.

IV. NEED FOR CLEAN COAL TECHNOLOGIES

Coal is now, and is expected to continue to be, the basic source of fuel for the generation of electric power into the next century. At present 56 percent of current electric generation comes from coal. This share is likely to increase in the future.

At the same time, substantial progress is being made on reducing environmental emissions. Since 1973, the emissions of sulfur dioxide emission in the U.S. have been reduced by almost 30 percent. This reduction occurred at the same time the use of coal was increased by 70 percent.

It is obvious, however, that current environmental control capabilities must be improved by reducing capital and operating costs and preserving overall plant productivity. It now costs three times more to build a new conventional coal-fired unit than it did in 1967. Over 30% of the cost of a large conventional coal-fired powerplant is directed toward environmental control. This includes sulfur dioxide scrubbing, particulate control, solid waste disposal, water treatment and plant cooling. These environmental controls in their current form also have a major impact on plant efficiency and reliability.

Only with a fundamental improvement in our coal burning technology can we respond effectively to the constraints placed upon these plants while also meeting our customers' needs for electricity. Siting and environmental demands must be met without sacrificing productivity. Requirements for new capacity vary widely and modular design and construction are almost a necessity to meet these needs in a cost-effective manner.

We cannot overstate the importance of our need to better meet actual demand growth at the least cost. Uncertainty with regard to how utility management will meet the future demand for power is of overwhelming concern to today's utility organizations. To the extent that modular, more efficient technology can be developed that reduces the time needed to meet increases in demand, a significant portion of this uncertainty can be resolved. Of equal importance is the ability for these new technologies to be introduced at a scale that more closely matches load increases.

The development of clean coal technologies will provide electric utilities with a wide array of alternatives. While no single option will satisfy the widely varying needs and operating conditions of utilities, as a group they offer tremendous potential. Unlike currently available pulverized coal-fired generating units with their flue gas desulfurization systems, new clean coal technologies are expected to meet the demand for environmentally acceptable coal use at less cost and with greater efficiency. Some offer the advantage of nitrogen oxide control in addition to sulfur dioxide control. They avoid or reduce the sludge problems associated with scrubbers and, in some cases, produce marketable by-products.

These new technologies also are expected to generate more power with less fuel and with reduced operation and maintenance costs. Many can be constructed rapidly in increments or modules over a wide range of unit sizes, thus better matching capacity to actual demand. By simply shortening the time from the decision to build a plant to commercial operation, there is a greater possibility of matching supply to demand, thus further reducing consumer costs.

More specifically, various technologies currently under development have the potential to:

1. Provide moderately efficient retrofit SO2 and NOx controls at far less capital cost than conventional wet flue gas desulfurization (FGD) and postcombustion NOx systems. Clean coal technologies can span the gap between relatively low cost, but less effective emission control represented by coal cleaning and the high cost, highly effective emission controls represented by FGD and SCR (Selective Catalytic Reduction). Examples of these technologies include low NOx burners and dry SO2 controls such as furnace and duct sorbent injection. These control processes are particularly cost-effective at smaller plants with short remaining useful lives and low capacity factors.

2. Provide economical alternatives to repower existing facilities resulting in extended plant life and additional capacity. Combining emissions control with the combustion or conversion process (e.g., fluidized bed, both atmospheric (AFBC) and pressurized (PFBC), or integrated gasification/combined cycle) results in systems which are less costly and

more efficient than those removing pollutants from the flue gas of conventional pulverized coal boilers.

3. Provide for new generation needs with technologies -- such as fluidized bed and coal gasification combined cycle -- that are less costly than current pulverized coal plants with FGD systems. These savings can be particularly dramatic at smaller scale units (200 to 300 MW) because of the increased opportunity for modularity, reduced construction time, and NOx reduction. Fuel flexibility (e.g., with FBC systems) adds additional cost savings. Because pollution control is inherent to the process, these new technologies do not require the use of high-cost flue gas treatment systems.

Emerging clean coal technologies clearly have the potential to permit the use of abundant domestic coal resources with less environmental and economic cost. Domestic markets for coal would be maintained and could even be significantly enhanced if these technologies reach widespread commercial use. They also may encourage the export of U.S. developed clean coal technologies and of U.S. coal.

V. COMMITMENT TO CLEAN COAL TECHNOLOGIES

Our nation has made a substantial commitment toward bringing new and cost effective technologies that use coal in an environmentally acceptable manner to the commercial marketplace. A recent Department of Energy report indicates that from 1980-1985 alone, "the U.S. -- through both public and private financing -- spent approximately $3.2 billion on the development of new coal technologies. Of this, the research, development and demonstration of new coal-based technologies to control sulfur dioxide and nitrogen oxide accounted for more than $1.6 billion."

The electric utility industry and others in the private sector have been enthusiastic and vital participants in this effort. Many individual utilities have spent many years and millions of dollars in the conduct of major technology development programs. The Electric Power Research Institute (EPRI), supported by voluntary contributions from investor-owned, government-owned and cooperatively-owned electric utilities, has invested $700 million in clean coal technologies. Over one third of EPRI's planned budget over the next five years will go to clean coal.

In addition, the utility industry has joined other interested industries in providing strong responses to Department of Energy solicitations under the current cost-shared demonstration program. When the Department solicited a first round of proposals for the program in late 1984, the private sector responded with 176 submissions identifying more than one dozen technologies that were near commercialization but required large-scale demonstration before the marketplace could put the technology to use. The second solicitation for statements of interest specifically emphasizing technology suitable for retrofitting, repowering, or modernizing existing powerplants drew 139 submissions with total project values exceeding an estimated $5 billion.

This demonstrated commitment of industry to the development of clean coal technologies is strong evidence of the utility industry's desire to remain responsive to the electricity needs of our customers and the environmental needs of our country. Clean coal technology development is a productive use of dollars and one which our industry is willing to pursue. The efforts of some in the Congress to impose mandatory emission controls is not an advisable course of action. If any legislative proposal to impose controls which is now pending before the Congress were enacted, the adoption of promising technologies by the utility industry would be severely retarded. Utilities would have little choice but to comply with the mandatory requirements by using existing technology.

The benefits of the clean coal program are so important to the energy future of the United States, as well as to the environment, that they should not be compromised. It simply is not desirable to have the nation spend billions of dollars on existing technologies that do not measure up to the potential of the wide array of new clean coal technologies.

VI. CONCLUSION

Enactment of legislation, such as S. 879, is the next important step in making new clean coal technologies a principal means by which US coal will be used more extensively. Our use of clean coal technologies can advance environmental goals, improve the efficiency and cost effectiveness of our electric utility system, and provide electricity for American industry that helps them to compete effectively in world markets. EEI encourages the Congress to move forward expeditiously to implement this critically important program.

The **Chairman**. Let me interrupt you there before I have to go off to ask one question, and that is, what do you think about this proposed idea that some have alleged to us that we ought to have some variable fee starting very low for pollution, which in turn would be used to both fund clean coal technologies and to aid in the cleanup?

Mr. **O'Leary**. This is not novel. This is a proposition that has been kicking around in these halls for about 20 years.

It has come up a number of times in early legislative proposals. It has never really made it. And I suspect that you would have difficulty in getting it through the Congress today.

I think it otherwise is a perfectly legitimate and useful device for getting there. But in addition to perfectly legitimate and useful, you have to find passable, and I am not sure that it meets that last test.

The **Chairman**. I am going to have to leave. I am late for my other appointment. I am very sorry to have to do so to miss Ms. Gonze's testimony and miss the questioning of you.

But I want to thank you and all the witnesses and also thank Mr. White, whom I will not be able to see. I understand you have to leave fairly quickly. But Senator Ford has indicated he can stay, and thank you very much.

Senator **Ford** [presiding]. Ms. Gonze.

STATEMENT OF RUTH GONZE, ASSISTANT DIRECTOR, GOVERNMENT RELATIONS, AMERICAN PUBLIC POWER ASSOCIATION, ACCOMPANIED BY LARRY BRONEILL, STAFF ENGINEER

Ms. **Gonze**. I am Ruth Gonze. That rhymes with bronze.

Senator **Ford**. And now we know.

Ms. **Gonze**. That is so. I represent the American Public Power Association, and with me today is Larry Broneill, staff engineer for APPA, who I may call upon on some of the more abstract rate regulatory issues which can arise in connection with this issue.

About 700 public power systems buy power at wholesale from investor-owned utilities in transactions which are regulated by FERC. And in addition public power systems generate about 10 percent of the nation's power supply today.

We support the development of clean coal technologies, and the establishment of Federal grant programs to achieve it. We also support effective, economical and fair acid rain control legislation.

One element in such legislation should certainly be setting compliance dates, which allow the use of clean coal technologies.

I have an observation to make here, somewhat casually, on the earlier testimony of Mr. Hawkins, talking about the need for 12 million tons per year. I would observe that several Congresses back we could have had a 6 million ton bill at that time.

That kind of reduction was long since rejected by the environmental community. But had it been adopted at that time, even 4 years ago, we would have 24 million tons less emissions in the air today.

And each year that legislation is delayed by the insistence on very high, even draconian levels of reduction, the less emission reduction we achieve.

We do not, however, support the achievement of emission cuts through, first, rate incentive programs which are designed to confer competitive advantages to the coal and private utility industries over other fuels, other technologies, and other sectors of the utility industry.

Or through, two, viciating the consumer protections in Federal and state rate regulation. This bill would provide Federal grants for projects which will provide necessary experience to reduce the risks of clean coal technologies.

But the major impact of the bill comes in the rate provisions of section 5. It is very important to understand, in talking about the rate breaks in this bill, that they are not dependent on the need for any more experience of any kind whatsoever, but are given for achieving widespread use of technologies which are already fully commercial.

Widespread use is not defined, and would appear to be virtually unlimited in its application, going all the way up conceivably to 100 percent use or one or another clean coal technology in all the power plants in the country, there being no upper limit to its definition in the bill.

The purpose of subsidizing widespreadness with ratepayers' money is apparently to make it profitable enough to clean up emissions that private utilities will forget how much they oppose such cleanup and rush to the rescue of air quality.

S. 879 would bestow a range of advantages of expenditures which would be placed largely beyond regulatory scrutiny.

For example, utilities can build complete new plants and rebuild old plants with a collection of rate breaks, whether of not that plant has anything to do with a clean coal technology, just as long as the plant also happens to use a clean coal technology.

Second, the bill skews utility decisions toward capital intensive technologies, and against equally good options which have to meet ordinary prudency tests and regulatory scrutiny and are allowed ordinary profits.

That kind of option would include fuel switching, conservation, photovoltaic cells, and natural gas generation. This is not an even playing field for fuels or technologies.

Third, this bill is more expensive for any given level of emission reduction than any flexible and moderate mandated emission reduction bill. No mandated emission reduction bill provides for full CWIP plus 5 year amortization for cleanup technology and modernizing power plants.

No such bill provides incentive rates of return or a presumption of prudency for new plants, and retrofitting existing plants which happen incidentally also to use a clean coal technology.

No such bill provides for exemptions in the discretion of the secretary from the Public Utility Holding Company Act and parts 2 and 3 of the Federal Power Act. No such bill abandons the principle consumer protections of the Federal Power Act or proposes that the states abandon their own protections.

Fourth, the bill would legislate rate breaks only for Federal regulation of wholesale sales, thus making 19 percent of electric sales the driving force behind the program. The success of the program depends upon the states following suit with similar rate breaks for retail regulation.

But there is nothing in the law now that stops states from adopting rate breaks for private utilities, from passing all risks on to ratepayers, and for making utilities a profit offer they can not refuse.

If the states do not go along, the situation will be this. The portion of the utility's rate base, represented by wholesale customers, is in most cases not going to be large enough to provide an effective incentive to use clean coal technology if the alternative choice is to do nothing.

But where utilities do want to put in clean coal technologies, and a number do, they are given the additional incentive that they can do it with generous help from wholesale customers who are their competitors at retail.

Potentially, some competition can be put out of business and that could indeed tip a decision in favor of going ahead with a clean coal technology project.

The result is that a likely outcome of S. 879 is that it will fail to achieve widespread use of clean coal technology, but it will spell success for some private utilities in gaining anti-competitive advantages over non-profit public power systems.

If the Committee, despite the bill's anti-consumer, pro-industry approach to environmental preservation, determines to back it in any part, then equal application to state retail regulation and Federal wholesale regulation is essential to minimum standards of fairness.

What is good for one is surely as good for the other. It should be unacceptable to charge the costs of a national program to a minority of American ratepayers. Thank you, Senator Ford.

[The prepared statement of Ms. Gonze follows:]

AMERICAN PUBLIC POWER ASSOCIATION
2301 M STREET NW WASHINGTON DC 20037 • 202/775-8300

Statement
of
Ruth Gonze, Assistant Director of Government Relations
AMERICAN PUBLIC POWER ASSOCIATION
before the
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
on
S. 879, "CLEAN COAL TECHNOLOGY DEPLOYMENT ACT OF 1987"

May 18, 1987

My name is Ruth Gonze. I am the Assistant Director of Government Relations of the American Public Power Association. APPA is the national service organization which represents more than 1,750 local, publicly owned electric utilities throughout the United States. More than 700 local public power systems purchase all or part of their power supply from investor owned utilities in wholesale transactions regulated by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act. About one-third of public power systems generate all or part of their electric power needs, and these systems provide about 10 percent of the nation's electrical generation.

S. 879 would provide federal grants to clean coal technology (CCT) projects, and would confer certain wholesale rate "incentives" upon investor owned utilities which undertake CCT projects. Further, CCT projects are given a presumption of prudency for purposes of state retail rate regulation; and the states would be "encouraged" to adopt the rate incentives given to FERC-regulated wholesale sales.

Public power systems would be eligible for federal grants under Section 4 of S. 879, but would not benefit from the provisions of major effect in the bill -- the rate incentives of Section 5. Public power systems are non-profit enterprises. Measures to increase utility profits are inapplicable to them, and equally inapplicable to rural electric cooperatives. Together, these industry sectors serve 25 percent of the nation's electric consumers.

APPA believes that if national policy calls for encouragement of industry-wide utility initiatives, such encouragement should not be targeted to one segment of the utility industry alone, and should not prefer one mode of utility organization over others. Grant programs, as provided in Section 4, provide an evenhanded treatment of industry sectors. Rate incentive programs give preferential treatment to investor owned utilities.

But S. 879 would go further than preferential treatment: its mandatory rate breaks would grant extra profits to private utilities at the expense of, exclusively, their wholesale customers and the ratepayers of these customers. As stated above, 700 public power systems are wholesale customers of private utilities. The incorporation of this bias targets one class of electric customers as the cash register for a program of national scope.

The provisions of Section 4 for grants for CCT commercialization projects require a determination that a project will "provide experience necessary at a commercial scale to reduce the technological, financial, and regulatory risks associated with such innovative clean coal technology."

But the bill's central provisions -- Section 5's special rate breaks -- do not require that a project provide any needed experience. Here, all that is required is that the Secretary of Energy make generic "estimates" of the technology's benefits (not of any project's) "in its widespread commercial application", and such estimates are required only "to the extent such information is practically available."

If such information is not available, presumably estimates of benefits may be dispensed with altogether. Moreover, benefits themselves, other than to the profit ledgers of utilities, are not required of any individual project -- except in the limited case where the heavy burden of proof to rebut a presumption of prudency might succeed.

Section 5's special rate breaks are given to CCT projects to assure their widespread use -- that is, after they are fully demonstrated and commercial, but not yet widely used. The bill does not define widespread use, and the rate breaks are permanent. There is no sunset provision for the bill or the breaks. "Widespreadness" could mean anything up to use of one form of CCT or another in 100 percent of coal-fired powerplants. If a concept as dubious as favoring "widespreadness" of one fuel or technology over others is judged worthy of large, federally mandated subsidies from a small segment of electric ratepayers, certainly its meaning should be sharply defined and limited; but we believe the committee should reject this coal and utility industry relief proposal entirely.

There is a basic conflict (and bias toward private utilities) in Section 5's regulatory liberality and Section 2(a)(4) and (5) of S. 879's Findings and Purposes, which state:

> "(4) the magnitude of the risks associated with the commercialization of these technologies are not compatible with normal electric utility rate-making procedures;
>
> "(5) establishment of the clean coal technology deployment program will better enable the private sector to assume those technological and financial risks that are attendant to the commercialization of emerging clean coal technologies;" (emphasis added)

These paragraphs find that the suspension of normal ratemaking protections is needed and justified to address the risks of commercialization. The special rate treatment in Section 5, however, goes far beyond "risk" or "commercialization." Rate breaks are given for fully commercial, "emerged," demonstrated, little-or-no-risk technologies. Either the "Findings and Purposes" provisions of S. 879 must be revised to reflect the fact that "risk" and "commercialization" are not involved here, or Section 5 must be revised to incorporate a requirement that "risk" be significant and that the technology require further demonstration. Neither change, however, would sufficiently protect the public interest.

Even the "Findings and Purposes" evidence a bias toward investor owned utilities. Note that Section 2(a)(5) explicitly espouses an intent that the CCT deployment program enable the "private sector" to commercialize clean coal technologies. This may reflect merely a certain obliviousness to public entities on the part of the originators of this proposal. But we wish to call the committee's attention to the fact that CCT may be deployed equally well through public entities.

The achievement of substantial pollutant emission reductions is an underlying purpose of S. 879. (See Section 2(a)(3).) If the program were successful (that is, if the states were to follow the federal "model" of rate breaks), its principal accomplishment would in fact be substantial emission reductions and more use of coal, an abundant resource.

S. 879 differs from mandated emission reduction bills in that it would attempt to achieve "widespread" cleanup by using ratepayers' money to make private utilities an offer they can't refuse. We submit that private utilities cannot have it both ways: they cannot maintain that large emission cuts are unwarranted; would raise electric rates drastically; would hurt the economies of their states and close down industries -- and that, on the other hand, if they are guaranteed that spending will be passed onto wholesale ratepayers without normal scrutiny, and are able to shift the burden of proof for imprudent or excessive expenditures, and are allowed to decide how much emission reduction is consonant with profits to them, rather than costs or benefits to citizens and ratepayers -- then, they will support legislation to achieve widespread cleanup.

This juxtaposition of positions contains a particular irony in that, for any given level of emission reduction achieved (short of draconian cuts -- 12 and 14 million tons of SO_2), S. 879 would probably be more costly and more economically damaging than mandated reductions. No mandated reduction bill provides for full construction work in progress, plus five-year amortization for cleanup technology and for retrofit, repowering, and modernizing powerplants. No such bill provides incentive rates of return, or a presumption of prudency for new plants and modernization of existing plants which happen, incidentally, also to use a clean coal technology. No such bill abandons the principal consumer protections of the Federal Power Act or proposes that the states abandon their own consumer protections.

S. 879 is also more costly than moderate mandated reduction proposals for another reason. S. 879 heavily skews rate regulation toward capital-intensive, coal-only technology, for both existing and new plants, and against equally worthy emission reduction and power supply options which must meet ordinary prudency tests and regulatory scrutiny, and are allowed only ordinary profits. These would include coal washing, fuel switching, conservation, fuel cells, photovoltaic cells, natural gas generation, and nuclear power. In S. 879, the important goals of making coal environmentally clean and capable of meeting competition on an even playing field has been overtaken by the prospect of making coal clean -- and first in profits, permanently.

Section 5 Rate Incentives

- Section 5(a) would require the Secretary of Energy to designate which clean coal technologies are eligible for a range of special regulatory rate privileges. When a technology is designated, the particular rate breaks to be provided for wholesale electric sales regulated by FERC must be specified, as well as whether the rebuttable presumption (in Section 6(b)) that any clean coal technology expenditure is prudent is applicable at the state level.

No criteria are provided for DOE's choice of rate breaks applicable to any technology. No standard of need for, or public benefit from, a special break is given. The Secretary may apparently give higher incentives because a technology is very promising, or because it is unpromising and needs all the help it can get.

- The Secretary designates which technologies are to receive special breaks, and which particular choices from the menu the technology gets. Assuming all courses are served, no examination of individual projects is permitted, except for the marginal nod to consumers that they may attempt to rebut the presumption that all expenditures are prudent. FERC must approve all individual project expenditures as just and reasonable, and may apply no safeguards against excessive or unreasonable rates or charges.

The safeguards foregone would include, for example, FERC's current use of the criterion of "reasonable market price" in judging utility expenditures. Pressure on utilities to manage these projects carefully would also be lost; when costs are not subject to regulatory scrutiny, and when all expenditures go into the rate base as incurred, ratepayers bear all the risk of bad management.

S. 879 would force wholesale ratepayers to bear all risk (for their share of the rate base) for retrofit of existing plants; and if the states can be persuaded, retail ratepayers would lift the rest of the risk from utility shareholders, while still preserving -- and raising -- shareholder profits.

This legislation would exempt a large class of expenditures from regulatory scrutiny, and then would bestow lavish advantages on these unexamined expenditures.

Rate Base Treatment for Unnecessary Costs

- S. 879 would give large rate breaks for the (unexamined) capital and operating costs for building new powerplants and rebuilding old plants which happen also to use clean coal technologies. The new construction need not be necessary to the use of the clean coal technology. All construction and retrofit costs, whether necessary to the use of clean coal technology or not, receive special rate breaks.

Consider some examples: a utility builds a new integrated-gasification -- combined-cycle plant. The gasification unit is a clean coal technology. The combined-cycle plant is a powerplant, not particularly innovative, not dependent on use of CCT, and not built in order to use CCT, but in order to meet load growth. The combined-cycle plant gets: (a) a presumption of prudency; (b) automatic approval of its design and engineering costs as "just and reasonable" operating expenses; (c) on application, five-year amortization and rate base treatment; (d) on application, an incentive rate of return.

Take an old powerplant instead of a new one. It has high pollutant emissions, and the utility converts the boiler to a fluidized bed combustion (FBC) boiler. The new FBC boiler is a clean coal technology. But along with the boiler, the utility replaces an old generator which has nothing to do with CCT, puts in a new control room, and refurbishes the offices, whose real-bamboo wallpaper is peeling. Expenditures for these changes get the same generous treatment the IGCC plant got and more: full CWIP in rate base.

The Presumption of Prudency

- Section 5(b)(5) would establish a rebuttable presumption that any clean coal project expenditure is prudent. This provision is apparently related to apprehensions arising from recent highly publicized prudency reviews of nuclear powerplants. It is important to recognize that these reviews have been retrospective, and used to exclude from rate base facilities begun long ago and which should be ready for operation, but which can't operate for various reasons, or are unneeded because of capacity surpluses.

It is not appropriate here to discuss the individual merits of each such review; nor should the committee conclude anything on that question from the fact of such reviews. It _is_ pertinent that such prudency reviews have _not_ been used to deny utilities recovery of expenditures for research and development or for commercial demonstration of technologies. These expenditures have often had the prior support of state regulators. There is no reason they cannot continue to gain such support, unless lack of accountability is institutionalized by legislation such as S. 879.

FERC has authority now, under the Federal Power Act, to grant advance approval to high risk RD&D expenditures. We commend to the committee, as a model, the procedures of FERC to approve cost of service or rate base treatment of utility RD&D expenditures (18 CFR 33.22). Such expenditures could certainly include clean coal technology commercialization projects, but certainly not "widespreadness" undertakings, as they (and this bill) should not.

FERC's rules for approval of rate treatment of such expenditures contain various safeguards; S. 879's regulatory relaxations exclude such safeguards. FERC's tests for the adequacy of a project plan include:

"(1) Evidence that the RD&D objectives of the company or research organization have been clearly established.

"(2) Evidence that the plan evolves from these RD&D objectives and adequately utilizes the viewpoints of scientific engineering, industry, economic, consumers and environmental interests.

"(3) Evidence that an effective mechanism exists and is used for coordinating this research and development with other relevant efforts of national scope.

"(4) Evidence that the project or program is well conceived, and, if successful, has a reasonable chance of benefitting the ratepayer in a reasonable period of time, having due regard to the basic, exploratory or applied nature of each submitted RD&D project.

"(5) Evidence that whatever achievements may result, including knowledge gained or technology developed from the RD&D effort, if any, will accrue to the benefit of the sponsoring jurisdictional company(s) and its/their customers."

Prior regulatory support, with safeguards such as those adopted by FERC, should make prudency reviews unfrightening to utilities. But the fact that utility executives may be unnerved by accountability does not constitute a reason to lessen it. There are many and weighty public policy reasons to retain prudency reviews untouched.

Consideration of the prudency of investments in a generating facility is based on factors which are known to a utility, or should be known, when the investment decision is made. The major issues are whether the need exists for the capacity being constructed; and whether the means selected to meet that need are the most appropriate. When the prudency of an investment is challenged, the utility has the obligation to come forward with evidence that its decisions were prudent. The burden of proof rests with the utility.

The legislation would reverse this burden if the Secretary of Energy establishes a presumption (in rate proceedings before both FERC and state commissions) that all clean coal project expenditures were prudently incurred. The burden of rebutting the presumption that a decision was prudent must be borne by state or federal commission staff, or, more likely, customer intervenors. They would be placed in the extremely difficult position of trying to prove a negative -- that the utility's investment was not prudent.

The essential effect of a presumption of prudency is to shield utility executives (whose rebuilding of existing plants will put at risk solely the dollars of their captive ratepayers) from any meaningful oversight. There is no reason whatsoever why this presumption is appropriate. Utilities making investment decisions should have solid justification for their actions. If their actions are challenged, they should be ready to come forward with evidence which would lead the hypothetical "reasonable person" to reach the same conclusion as the utility's executives reached. It is unreasonable to expect that intervenors or others, who do not have the evidence which the utility has, can prove that the decision should not have been made.

Exemptions from the Public Utility Holding Company Act and the Federal Power Act

Section 5(c) permits the Commission to exempt any person from the provisions of the Public Utility Holding Company Act, and Parts II and III of the Federal Power Act, to the extent that either Act applies due to ownership or operation of a clean coal project, and the Commission determines that the exemption would be necessary to permit the person to participate in the project. This provision is patterned after Section 210(e)(1) of the Public Utility Regulatory Policies Act, which provides similar exemption authority to the Commission for qualifying cogenerating facilities and qualifying small power production facilities. Presumably, there is concern that some potential participants in clean coal projects will not participate if they run the risk of regulation under either the PUHCA or the FPA.

There is a significant difference between PURPA Section 210(e)(1) and Section 5(c) of this bill. The exemption in PURPA applied to qualifying cogenerating and small power production facilities. By definition, such facilities must be owned by persons not primarily engaged in the generation of electricity. Thus, the PURPA exemption was designed to clear the way for non-utilities to participate in the cogeneration and small power production program.

Section 5(c) is far broader. It applies to any person, utility and non-utility alike. While it may be desirable to encourage non-utility participation in clean coal projects, and while such participation may depend on exemptions from PUHCA and FPA, it is not apparent that exemptions are required to encourage utility participation.

Further, it is not apparent why exemptions from Part II of the Federal Power Act are necessary. Obviously, such exemptions were necessary under PURPA since the PURPA program envisioned sales of power from qualifying facilities to electric utilities, which were free of the requirements of traditional rate regulation set forth in Part II of FPA. That is not the case here. We would recommend that all reference to exemption from Part II of FPA be deleted.

We urge the committee to examine Section 5(c) carefully. The Public Utility Holding Company Act and the Federal Power Act are important consumer protection statutes, the application of which should not be waived absent sound justification. We believe that if authority to exempt entities from these two statutes is granted to FERC, that authority should extend only to non-utility persons, or, at the most, to joint projects in which there are utility and non-utility participants.

The Inclusion of Taxpayer Grant Funds in Utility Rate Incentives

S. 879 would permit utilities to charge expenditures made with grant funds from taxpayers to ratepayers, and to reap the entire collection of rate benefits provided in Section 5 from these funds.

Section 4(a)(5) provides that grant assistance may not exceed 50 percent of "clean coal expenditures." Section 3(5) includes all "clean coal capital cost" in the class of "clean coal project expenditures." These "expenditures" are then defined as all costs or expenses related to design, construction, or operation of new facilities and the retrofit, repowering, or modernization of an existing facility, which happen to use a clean coal technology.

We believe the committee will need no further comment to take action to exclude such abuse of public funds.

Using Wholesale Customers as Lever and Cash Register

The purposes of S. 879 conceive the "widespread use" of clean coal technologies as essential to the success of the program. The drafters clearly recognize that without the participation of the states, the program will fail.

Thus, several provisions are directed to inducing states to copy the federal utility rate incentives of Section 5. There is a presumption of prudency at the state regulatory level if the Secretary of Energy so directs; the Secretary must consider whether a state has adopted the Section 5 rate breaks in awarding grants to projects in the state; federal "encouragement" to the states to adopt the Section 5 rate breaks is required.

Nevertheless, the provisions affecting states may have only slight force. Compared to the rate liberties allowed for wholesale sales, the requirements on states are barely perceptible.

It is important to recognize that nothing prevents states, including the five state members of the Clean Coal Technology Coalition, from adopting private utilty rate breaks like those in Section 5, if they wish to encourage CCT by reducing regulatory scrutiny, passing little-examined risks onto ratepayers, and conferring large profits on utilities at the retail level. Surely, they are not prevented by the fact that 19 percent of electric sales would retain traditional rate regulation if this bill fails. If that were so, then certainly the fact that 81 percent of electric sales would retain most traditional regulation under this bill will prevent the Congress from approving S. 879.

The question thus arises, what happens if the states fail to follow suit? Denied rate breaks at the state level, most utilities would find that the small percent of their rate base allocated to wholesale customers would not justify significant new investment. For them and their regions, the bill would fail altogether.

Some utilities, however, may already be contemplating the installation of clean coal technology. Projects under way now include the following:

- The Tennessee Valley Authority has undertaken a new 160 megawatt atmospheric fluidized bed combustion (AFBC) project.
- Northern States Power Company is retrofitting an AFBC boiler to an existing unit.
- Colorado-Ute Electric Association is constructing the first U.S. circulating AFBC bed boiler.
- Southern California Edison has brought on line the first commercial demonstration of integrated-gasification -- combined-cycle technology.
- The Richmond, Indiana, Electric Department will install a Limestone Injection Multistage Burner (LIMB) system at its existing 60 megawatt powerplant.

For utilities already considering a clean coal technology project and which sell power at wholesale, S. 879 does offer a decided incentive. They obtain a double opportunity: to reduce emissions with generous help from wholesale customers, and to put these customers, who are competitors at retail, at a serious competitive disadvantage.

Thus, a likely outcome of the passage of S. 879 would be failure to achieve its goal of widespread use of CCT, but success for some private utilities in enhancing anticompetitive advantages over local publicly owned electric utilities.

Under the Federal Power Act, FERC is required to consider whether a proposed wholesale rate would result in a price squeeze for the purchasing utility. A price squeeze exists when a buying utility's wholesale rate is so close to the seller's retail rates as to endanger the ability of the wholesale buyer to compete at retail. Anticompetitive price squeeze situations can cause wholesale buyers to lose customers to the power supplier, and if serious enough, can eventually force the sale of the system to the power supplier. The law now requires FERC to adjust wholesale rates to prevent or mitigate the effect of a price squeeze.

S. 879 would create price squeeze situations by requiring huge, nondiscretionary, unexamined rate breaks for wholesale sales regulated by FERC since 1935, which are applicable only at the federal level. Thus, in states which do not allow comparable windfalls to utilities at retail, gravely serious price squeeze problems could arise. Some distribution utilities could be forced out of business from the combined impact of S. 879's rate hikes. The largest single component of the damage may result from the requirement to pay amortization charges at the rate of 20 percent per year, while retail customers pay at about 2 to 5 percent per year.

At the same time, s. 879 prohibits any remedy through FERC, by requiring the Commission to find all of the bill's "incentive" rate breaks just and reasonable.

If the committee, despite S. 879's costly anti-consumer, pro-industry approach to environmental preservation and CCT development, determines to act favorably on any of its rate provisions, we believe that equal application to state retail regulation and federal wholesale regulation is essential to minimum standards of fairness.

APPA strongly urges the committee to reject a program which: is devised to advantage the coal industry and private electric utilities; is likely to fail to achieve "widespread use" of clean coal technologies nevertheless; discriminates against non-profit utilities, serving 25 percent of the population, in its rate incentive provisions; places wholesale power purchasers at a competitive disadvantage; and charges the costs of a national program to a small proportion of American electric ratepayers.

Senator **Ford**. Thank you, Ms. Gonze. I think you have stated your case very well.

Acid rain has been washed through here two or three times today by practically every witness. Let me ask both of you, would the enactment of current proposed acid rain legislation impact the development of clean coal technologies?

Ms. Gonze, we will let you answer first.

Ms. **Gonze**. Senator, I believe that if acid rain control legislation is enacted with short deadlines that do not take into account the expected availability dates for clean coal technology, such as the early 1990s for some of them, the mid 1990s for some others, and possibly later for some of the more complex ones, then I believe that that legislation will inhibit the development of clean coal technologies.

And the principle requirement for coordination between acid rain legislation and clean coal technologies is that the compliance deadlines be adjusted to suit one another in order that we can use these technologies.

Senator **Ford**. Let us try the flip side of that. Would a good clean coal technology bill delay the enactment of acid rain, in your opinion?

Ms. **Gonze**. We would hope it would not, and we would oppose any connection between the two.

Obviously, clean coal technology is a good thing. It should be funded. Grants for it, matching grants are a good thing. We favor the grant provisions of this bill, the grant proposals of the Reagan administration, and existing programs.

There is no reason for the two to hinge upon one another. I understand, when I read the rate regulation sections of this bill, why people think that there is an attempt to substitute the one for the other.

It does make one paranoid. But insofar as any necessary connection between the two goes, there is not any.

Senator **Ford**. Mr. O'Leary, would the enactment of acid rain legislation that we have out there, the so-called Mitchell-Stafford legislation, would that impact the development of clean coal technologies in your opinion?

Mr. **O'Leary**. I think it clearly could, Senator Ford. If the timetables are such that they require the adoption of existing technologies, then I think a lot of the incentives go out of the system for developing the new ones.

Ms. **Gonze**. Senator Ford, in your having mentioned that you wanted a specific comment on Mitchell and Stafford, I could very definitely tell you they most certainly would, because they are plant by plant.

Limestone injection multi-stage burners, for example, which only provide a 50 percent reduction in emissions would not be useful for complying with either Stafford or Mitchell. Those are plant by plant reduction bills, and very few technologies can meet them.

Senator **Ford**. What about the flip side of that question then, Mr. O'Leary? How would the development of clean coal technologies affect the enactment of acid rain bills?

Mr. **O'Leary**. Well, speaking personally, Senator, I believe really they are on different tracks.

Clearly they relate to one another. The burden of my testimony was that we have a very large and unresolved national problem that in my judgment this bill, or one very close to it, could address.

At the same time it is quite clear that there are other committees of the Congress that are addressing the acid rain problem on a somewhat shorter track. My own judgment is that we have the luxury of time here, that we can afford to understand a little bit better than we are dealing with.

Every time I read the literature and get a literature update on this over the last 15 or 20 years, I find that our appreciation of it has changed significantly.

And I think it is reasonable to say that we are still underinformed when it comes to putting out a very, very sweeping piece of legislation on how to fix a problem that we really can not define all too well.

Senator **Ford**. You said earlier in your discussion with The Chairman that utilities would be very reluctant to invest money in new technologies, trying to make investments in the future.

So you are saying to me, I guess, or saying to the Committee that if we are going to have new technologies, the Federal government is going to have to get involved in trying to put the petrol in the motor that drives the effort for new technologies.

As you also said, there is support from the utilities as it relates to organizations, but not the large investments. How many clean coal technologies demonstrations do you believe we must have that are successful in order for other utilities and public service commissions to see this technology as successful.

Mr. **O'Leary**. I do not think you can answer that with regard to all applications. I have looked very carefully over the last close to 15 years now at the evolution of the atmospheric fluidized bed technology, as it applies to clean coal burning.

In my judgment, we are going to have to have two or three successful, at least, full-scale demonstrations of that before that is going to be regarded as settled.

I suspect that there are other technologies that can be well-demonstrated with a single large and successful prototype plant. I am thinking for example here one of my favorites, although not popular at the moment, is the Great Plains plant.

It is running very well. Its costs are coming down all the time. And it seems to me that the thing that I set out to prove in sponsoring that plant in North Dakota has been pretty well demonstrated.

Now in the meantime the market has gone away. But that single large plant has, to I think most people's satisfaction, demonstrated that you can have a big high BTU gasification facility based on coal with technologies that are at hand.

So it really depends on the technology, how delicate it is, to get to an answer of that. But I think the answer is not very many in any instance. We are not asking, you do not have to do 10, for sure. But two or three typically, in some instances as few as one.

Senator **Ford**. Is the 160 megawatt demonstration project at Shawnee one of those in the fluidized bed combustion operation, is that large enough once it gets into place and is demonstrated for a period of time, is that a large enough operation for a demonstration?

Mr. O'LEARY. Senator Ford, I do not think it is. I think that you have to take that particular technology, probably up into the 200 megawatt to 250 megawatt range. Now that is a personal response.

Senator FORD. I understand. You have been at it a long time, and your personal feelings are very good.

Mr. O'LEARY. Let me just give you the problem of that. We used to think, 10 years ago, that you could build 10 trains of 100 megawatts each and get the equivalent, we always thought then, in terms of a gigawatt, a 1,000 megawatt plant.

My understanding in talking to the people that work this field, and I had a discussion with one today, the EPRI fellow that has done this for years, Kurt Yeager, and asked him what he thought of that concept.

He said the controls are just too complex. And it is much better to have four 250s than 10 100s, knowing as I do from my very recent experience in dealing with the control of nuclear facilities, I agree with that.

I think the control devices that are required to keep a family of these running in sync offers its own set of problems. The manifoldings, the economies of putting it in to one or two turbines, for example, putting that much energy into versus 10 turbines. You would really like to do it with four or even with two, and capture the economies there.

I do not think we can take the simple view that small trains multiplied can replace the current large 1,000 megawatt plants.

Senator FORD. Ms. Gonze, if you want to get in on this conversation you just jump right in.

But are we looking at a smaller unit, say the 250 megawatts, that can be built with new technologies or with a retrofit type. I am not sure where we would want to go on that.

But would that come closer to meeting the supply and demand than anything that we have seen?

One of the problems of going out here and building a big 700 to 1,000 megawatt operation and it is a long time coming on board, and you have to generate and then you have to sell, and you have some left over and you try to divert that somewhere to somebody else, and it gets to be a long term and all of a sudden you are short.

Are we in a better position with a smaller plant, say, 250 to 300 megawatts?

Mr. O'LEARY. I think far better. Let me just give you two ends of the scale.

First of all, if you are dealing with 50 and 100 megawatt units, you have to recognize that the permitting, the management preoccupation, the enormous amount of pre-construction work is about the same as it would be for a 250 megawatt.

It is how do you use the management capability of a utility problem? Do we have enough people around to be able to handle a multitude of 100 or 50 megawatt plants?

The answer is probably not. We can load follow nicely at the 200, 250 range. That, instead of having a very lumpy introduction of power, as we do typically now with nuclear generating units at 1,000 megawatts a crack, and with the attendant rate shocks.

This permits you to load follow in effect. To come up stepwise and pick that load up without a lot of capital sitting out there unused, a lot of interest accumulating, and altogether a much more attractive economic proposition while at the same time being large enough to warrant the management preoccupation that is necessary for the unit.

So I think that when all this settles down, and the choices are before us, instead of having the 850 to 1,100 megawatt unit as the size of choice, this industry is going to settle on 250 to 450 megawatts as the size of choice.

And of course the technology has got to come in synchronous with that.

Senator **Ford**. Ms. Gonze, would you like to comment? Do you have anything you want to follow up with?

Ms. **Gonze**. Senator, I do not have any fundamental disagreement with Mr. O'Leary here.

The point simply being that, yes, it is true that smaller incremental additions of capacity to match load growth seem much more desirable these days than gigantic jumps of 750 or 1,000 megawatts of capacity of some years back.

Of course, for public power we would think in smaller increments than Mr. O'Leary is thinking, 250 seeming fairly generous for the lower end of the range to me. And 150 seeming quite reasonable.

But that is probably a reflection of the difference between public and private power. I would note that the units, the combined cycle units now being installed by the General Electric Power Company are 210 megawatts.

Senator **Ford**. Fine. The hour is getting late, and I probably could ask some more questions.

But I do thank you and it may be that we will want to send some questions to you in writing and hope you would respond in a timely manner so they can be included in the record of these hearings. I thank you both.

Mr. **O'Leary**. Thank you, Senator.

Senator **Ford**. Jack, good to see you, my friend.

The next witness is Mr. W.S. White, chairman, American Electric Power Service Corporation of Columbus, Ohio, on behalf of the Clean Coal Technology Coalition.

Mr. White, we thank you for your patience, and we will nominate you for the Job award. You may proceed. If you want your statement in the record, why, we would be glad to put it there, and you can highlight it.

STATEMENT OF W.S. WHITE, JR., CHAIRMAN, AMERICAN ELECTRIC POWER SERVICE CORP., ON BEHALF OF THE CLEAN COAL TECHNOLOGY COALITION

Mr. **White**. I appreciate very much the opportunity to appear before the Committee today.

The Clean Coal Technology Coalition does support the program proposed by Senator Byrd in S. 879. We believe that the clean coal technology initiative announced by President Reagan on March 18th can be made fully compatible with the provisions of Senator Byrd's bill.

Thus we do encourage the Committee to reconcile the differences between these two proposals and to favorably report clean coal technology deployment legislation.

The proposed deployment program is important to customers of the utility industry, because we believe that our nation's energy security and economic well-being, including our ability to compete in the international marketplace, clearly are linked to the use of coal in cost-effective applications.

To meet the projected electricity demands of our nation in the next decade and beyond, we believe we have to demonstrate and then commercially deploy a variety of these new technologies.

New technologies for new generation, for repowering and for retrofit operations that can take full advantage of our vast coal resources and also efficiently meet our continuing obligations to our electricity consumers.

In terms of energy security and environmental policy, our nation has a great deal at stake here. Continuing and enhanced use of coal in a cost-effective and environmentally acceptable manner is quite possibly our single greatest challenge to coal use through the remainder of this century.

I would like to emphasize that the programs proposed by the president and Senator Byrd are not, as some groups have asserted, another coal research program. The research phase has essentially been completed.

What is intended now is that clean coal projects will be constructed at commercial scales with the objective of developing sufficient reliability of the technology so that the utilities and the regulatory agencies, which govern our activities, can count on these plants as being demonstrated, as useful, that they will work, and they will meet the availability requirements that we need to meet our customer obligations.

It is important, I think, to understand that we are a regulated industry. As such we are required to conduct our business activities under a set of regulatory principles which very frankly in recent years have led to an aversion to risk-taking. Several have spoken about this today.

I think this is totally understandable when you consider the realities of regulation as it is today. The electric utility industry's principle obligation, we feel, in fulfilling our part of the regulatory compact, is to provide reliable and cost-effective electricity.

Unlike unregulated entities in our economy, where successful technology innovation, if it is accompanied by risk, is followed by commensurate degree of economic reward, the risk-reward process is simply not available to the regulated electric utility industry.

Failure is borne by the shareholder, under the guise of imprudency, and success is passed on to the ratepayer. Senator Ford, this is a heads you win, tails I lose proposition.

Given that reality it should come as no surprise that our industry cannot casually assume the considerable risks associated with the introduction of new technology without a significant level of certainty as to how these risks will be treated by our regulatory agencies.

I am pleased that the program proposed by Senator Byrd recognizes the need to establish a greater degree of regulatory certainty for those who are willing to develop these technologies.

Our examination of S. 879 concludes that the bill does address that important objective. The program of direct Federal grants is important to buy down, I think is the language used in the Senator's bill, a portion of the risk associated with the first of its kind deployment of these new technologies.

In addition, S. 879 proposes several important regulatory changes applicable to the Federal Energy Regulatory Commission. These proposed regulatory changes are powerful tools we believe to attract investment into the regulated industry.

The legislation does not intrude upon the traditional rate making authorities of the states, but the proposal does encourage the states to use a Federal program as a guide when considering similar state regulatory incentives.

Some have questioned whether utilities will undertake to deploy these technologies without the proposed deployment program. A number of the technologies under development may well find their way into the marketplace without such assistance. But the pace of introduction is likely to be very slow and uneven.

Finally, as we have previously testified, enactment of acid rain control legislation will seriously impede clean coal technology development, if not eliminate active pursuit of these more effective, more cost-effective options to meet environmental objectives.

Without the scientific evidence to support a control program, it makes eminently better sense to pursue and deploy new clean coal technologies. In so doing we can better prepare for both the next generation of electric generating technologies and a more cost-effective array of retrofit options than conventional technology.

In conclusion, sir, we would we urge careful examination of this proposal, and I would be very happy to try to respond to your questions.

[The prepared statement of Mr. White follows:]

HEARINGS ON S. 879,
THE CLEAN COAL TECHNOLOGY DEPLOYMENT ACT OF 1987
BEFORE THE
SENATE ENERGY AND NATURAL RESOURCES COMMITTEE
U.S. SENATE
WRITTEN STATEMENT OF
W. S. WHITE, JR.
CHAIRMAN OF
AMERICAN ELECTRIC POWER SERVICE CORPORATION
APPEARING ON BEHALF OF THE
CLEAN COAL TECHNOLOGY COALITION
MAY 18, 1987

I. INTRODUCTION

This written statement is submitted by W. S. White, Jr., on behalf of the Clean Coal Technology Coalition.

The Coalition is an ad hoc group of electric utilities, equipment suppliers, coal companies, architect-engineering and construction firms, several state governments, the National Coal Association, the Edison Electric Institute and the United Mine Workers. A membership list is attached to this testimony for the information of the Committee (see: Attachment A). The Clean Coal Technology Coalition (CCTC or Coalition) was organized in early 1985 for the specific purpose of encouraging the demonstration, commercialization and widespread use of clean coal technologies.

The Coalition membership endorses the Clean Coal Technology Deployment Act of 1987 (S. 879) introduced by Senator Robert Byrd on March 30, 1987, and also supports the clean coal deployment program announced by President Reagan on March 18, 1987. The enhanced industry/government partnership to be created by the clean coal technology deployment proposals under consideration by this Committee is an important cost-sharing initiative which can accelerate the commercial utilization of emerging technologies. Success in this effort will allow for the use of coal in a cost-effective and environmentally acceptable manner.

The Coalition believes that the legislative hearings on S. 879 will greatly assist in focusing attention not only on the need to efficiently control emissions from the use of coal but also on the need to plan for and provide reliable and cost-effective electricity to American consumers.

The efforts of Members of the Senate Energy and Natural Resources Committee in the leadership role provided to demonstrate and deploy new clean coal technologies are to be applauded. We appreciate the difficulty each Member confronts as choices are made to establish clean coal technology development as a national priority while working within severe budget constraints. Continued support from Members of this Committee is an important indication to the utility and coal industries of the government's commitment to clean coal technology development.

This testimony is intended to complement testimony given before the Subcommittee on Energy Research and Development by Mr. A. Joseph Dowd, Senior Vice President and General Counsel of American Electric Power Service Corporation, on behalf of the Coalition on April 2, 1987. In that earlier testimony the Coalition set forth the reasons for establishing a clean coal technology deployment program and the principal elements of a program that would be most helpful in assuring accelerated and widespread deployment. Further, Mr. Dowd provided to this Committee responses to several additional questions from the Chairman of the Subcommittee, Senator Ford, and the ranking minority member of the Subcommittee, Senator Domenici. A copy of the written testimony and responses to the questions asked are attached to this statement for the information of the Members (see: Attachment B).

We appreciate this opportunity to comment upon S. 879. This written testimony addresses the following three areas:

1. Examines the specific provisions of S. 879 and comments upon the usefulness of proposed incentives to assure accelerated deployment of clean coal technologies.

2. Projected economic and environmental benefits that are likely to result from a successfully-executed clean coal technology deployment program.

3. Reasons why clean coal technologies are not likely to be deployed if current acid rain control legislation is enacted.

II. COMMENTS ON SPECIFIC PROVISIONS OF S. 879

The clear objective of S. 879 must be broad-based commercial deployment of clean coal technologies. The Coalition believes that our nation's energy security and economic well-being are linked to the continuing ability to utilize coal in cost-effective applications, and that, unless an expeditious and broad-based deployment of these technologies can be achieved, environmental concerns may lead to unwarranted regulatory actions which will be more costly, and ultimately less effective, than widespread utilization of clean coal technologies. To be successful in encouraging acceleration of clean coal technology use, a federal clean coal technology deployment program must be able to assist in lowering the risks of using new technologies and in creating a satisfactory level of certainty that costs -- if prudently incurred -- can be recovered from the investments made.

The risk-taking associated with investment in clean coal technologies is particularly acute in the electric utility sector which requires a high level of plant reliability and which depends upon regulatory approval to recover the cost of utility investments.

Typically, utility managers must satisfactorily answer the following questions before investing in clean coal technology:

> Will the technology work in commercial scale applications?
>
> Will the technology be sufficiently reliable that management may count on the plant being available to meet service obligations to customers?
>
> Will the investment be recoverable?
>
> Are there affirmative reasons (e.g., greater efficiency, reliability, environmental performance) to justify the time and money required for project development?
>
> Will changes in environmental regulation render the investment wasted and further jeopardize its recovery?

Changes in environmental regulations are not controlled by the utility; indeed, there can be no assurances given which bind future governmental actions. However, a good deal can be done to address the other technological and regulatory risks which inhibit investment in clean coal technologies. S. 879, we believe, if enacted as currently written, goes far toward reducing these risks and providing assurances that might better enable a utility to confidently undertake clean coal projects.

A. Overcoming the Impediments to Deployment and Establishing that the Technology will Work:

In the 98th and 99th Congresses, steps were taken to deal with the first important technological risks; namely, will the project work in commercial scale applications? The Clean Coal Technology Reserve was created, and significant monies set aside, to assist in the demonstration of the commercial feasibility of innovative clean coal technologies. A number of qualifying projects have been funded. The Coalition has recommended that a second round of demonstration projects be solicited to ensure that the majority of promising technologies now ready for demonstration are pursued. Clear justification for a second phase of the demonstration program exists, evidenced by the strong industry response to the Department of Energy ("DOE") solicitation for statements of interest in pursuing additional demonstrations. (See: Attachment C which describes the 139 clean coal proposals submitted pursuant to the latest DOE solicitation).

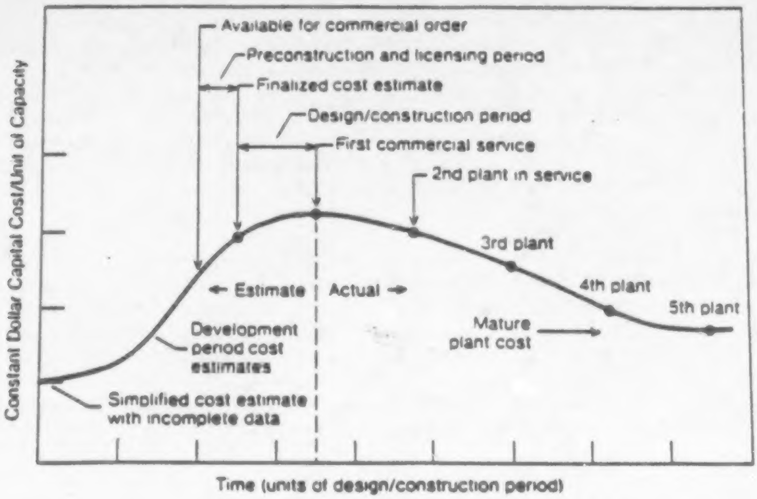
The Clean Coal Technology Reserve is a crucial and important first step in deployment. Over time, it will foster investments in technologies which have been successfully demonstrated under the current demonstration program. But, to achieve a broad-based deployment of these technologies and to hasten the pace of investment, more is required. The Clean Coal Technology Deployment Act of 1987 can answer this need.

B. Means By Which To Achieve Reliable Technology:

1. The Federal Grants Program

Even after commercial feasibility is demonstrated (the objective of the demonstration program), it is still not known when the technology can pass the test of economic viability which is required of utility plants. In supporting the cost-shared, multi-year grant program proposed by the President and by Senator Byrd, the Coalition believes that multiple plant deployment projects (at what would be considered utility scale) of the same or similar technology, under different and real world utility operating conditions, should be encouraged.

The objective of supporting multiple plant applications is to refine the technology so that its capital and operating costs can be minimized. The multiple plant demonstrations also offer the benefit of spreading among potential users the "hands on" technology so critical to the pace of market penetration to be achieved by a given technology. In the course of technology development, it is well accepted that the first commercial project using a new technology will cost more than that project which represents a subsequent mature technology. This developmental process can be depicted by the following chart:



Cost Learning Curve

S. 879 contemplates a targeted deployment program whereby the federal government could provide some degree of financial assistance to each project in this multiple plant maturation process. A deployment assistance program to provide grants of up to 50 percent of construction and operating costs is called for under the proposed deployment program. The grant program would make available $350 million per year over a ten-year period. President Reagan has proposed a 5-year, $2.5 billion program. In deciding upon the appropriate duration of the program and the amount of funding, the Committee should note that industry is not likely to be able to spend $5 billion (50-50 cost share) over a short five-year time frame, although commitments to spend are probably achievable.

2. Federal and State Regulatory Incentives

To complement this level of Federal assistance, S. 879 contains a series of initiatives designed to remove Federal regulatory impediments to utility investment in clean coal technologies and a program to encourage supporting state policies.

First, with respect to the State regulatory program, State prerogatives are preserved. Even though more than 80 percent of utility revenues are subject to the regulatory dictates of state and not federal authorities, the clean coal deployment strategy would seek to effect only modest influences on the exercise of state regulatory powers. Pursuant to S. 879, a program is established to encourage favorable action by states that would remove impediments and create incentives for investment in designated technologies. Essentially, reliance is made on the ability to persuade (i.e., jawboning) using the proposed Federal regulatory incentives as a guide. The only direct action taken is to create a presumption in favor of the prudence of investment in any of these technologies; but even this presumption is permitted to be rebutted if contrary evidence can be developed.

At the Federal level, where the exercise of Congressional authority has been pre-established and is unquestioned, more direct and more ambitious regulatory initiatives are proposed. But even here, it should be emphasized, the initiatives are constrained by the ability of the Secretary of Energy to determine which regulatory incentives will be made available for which clean coal technologies.

For example, in order to receive the benefits of the regulatory initiatives, the technology must first be designated as an eligible technology by the Secretary of Energy in accordance with statutorily-established criteria. Even then, the Secretary may choose among the array of regulatory initiatives so as to tailor the actions to be taken to the requirements of the particular technology. In this way, there seems to be a recognition that some technologies require only modest incentives for the utility industry to adopt while others may require greater, or different, assistance. The Coalition supports this flexibility.

Similarly, each of the Federal regulatory initiatives is targeted to accomplish a specific objective. These are discussed below in the order in which they appear in the Act (but not necessarily in the order of importance these initiatives may have for assisting in clean coal technologies development).

(a) Engineering and Design Expenditures. For Federal ratemaking purposes, the Federal Energy Regulatory Commission ("FERC") would be directed to treat utility expenditures for design and engineering work for a project using designated technologies as an allowable operating expense.

This provision could be utilized to assure utility management that if it proceeds to investigate the application of innovative technologies, through preliminary engineering and design studies, the utility can count on its ability to recover its prudently-incurred costs even if ultimately the project does not proceed beyond the preliminary engineering and design stage.

(b) Retrofitting, Repowering, and Modernization of Existing Facilities. The capital costs for certain clean coal projects would be permitted to be included in the utility's rate base when incurred.

This provision gives clean coal technology projects constructed in association with the retrofitting, repowering, or modernization of existing plants, comparable status to that afforded environmental control compliance equipment under existing FERC regulations: that is, to include the full amount of capital costs in rate base as these costs are incurred. It should be noted that this allowance is not required to be made available for new capacity additions, although FERC may exercise its existing powers to so provide if it becomes appropriate. Full recovery of capital costs, under S. 879, is limited to existing plant retrofit, repowering and modernization projects.

(c) Accelerated Amortization. Upon application, a public utility would be permitted to obtain a five-year amortization of its capital investment in qualifying clean coal projects.

This mechanism would allow the utility a more rapid recovery of its investment than may otherwise be the case, enhancing the investment's relative value. This incentive can be a particularly powerful inducement to discretionary investments in existing plants where an environmental gain can be achieved without having to wait for the full economic life of the plant to be exhausted before full capital recovery is provided. The provision is made elective to the utility to avoid dramatic rate increases in the case of particularly large capital investments. Further, it may be more appropriate with respect to this incentive to permit the utility an election of less than the otherwise useful life of a facility, but no less than five years. In this way customer rates would be insulated to the greatest extent possible.

(d) Incentive Rate of Return. When requested, the FERC is directed to provide for an incentive rate of return on clean coal project capital costs. The fixing of any such return, however, is left to the Commission's discretion.

This mechanism would allow non-utility, third-party project participants and co-venturers to earn comparable returns as may be available in non-regulated competitive investments. For utilities the incentive return, like other elements of S. 879, is intended to give a favorable bias to discretionary investment in clean coal projects. The Congress and the FERC have used the device of an incentive rate of return in other contexts to induce investment judged to be in the public interest. This provision builds on that precedent.

(e) Presumption of Prudence. The bill creates a rebuttable presumption that clean coal project expenditures are prudent. A similar presumption is to apply in both State and Federal regulatory proceedings.

Under traditional regulatory principles, utilities are entitled to recover and earn on only those investments which are prudently made. The rebuttable presumption of prudence for a clean coal investment is intended to acknowledge a strong national interest (a "public policy blessing") to this investment as a device for giving utility management more confidence than it may otherwise possess that discretionary investments in innovative clean coal technologies will be confirmed by regulators as prudent. Given the intensity of the regulatory controversies which have emerged over the last several years concerning capital expenditures for new capacity, many utilities, once affected negatively in a retrospective prudence hearing, have adopted strategic plans which contemplate making only those capital expenditures as are unquestionably required to satisfy customer service duties. The presumption of prudence for clean coal technology investment is designed to overcome this reluctance to do any more than that which is strictly required.

The presumption contained in Senator Byrd's bill is not absolute, however. It does not serve as an impermeable shield for imprudent conduct. Thus, the presumption is made rebuttable. It can be defeated by contrary evidence which convincingly demonstrates the utility acted imprudently with respect to a particular investment which may have been otherwise meritorious.

(f) FERC Exemptions. The last element of the Federal regulatory program is a grant of authority to FERC to create exemptions from the Public Utility Holding Company Act ("Holding Company Act") and from the Federal Power Act ("FPA") to the extent necessary to encourage investment in clean coal technologies. This is discretionary power similar in scope to that provided by the Congress for qualified small power producers and cogenerators under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

The reasoned exercise of these exemptive powers is believed to be essential if truly rapid and broad-based deployment of clean coal technologies is to be achieved.

The Holding Company Act is a deterrent to non-utility ownership of generation facilities. Moreover, the Act constrains utilities to operations within their own service territories or to investments in facilities the power output of which is consigned to the utilities' own customers. Such constraints on utility and non-utility entities retard the spread of technological innovation and inhibit technology transfer. It is often the case that new designs are first developed by non-utility vendors. If these entities are blocked from receiving the fruits of their technological innovation through the ownership of facilities, entrepreneurial incentive is diminished. Also, those utilities who are themselves developers of innovative technologies or those who have acquired valuable "hands on" technological operating experience have very limited marketing opportunities for their product. Relaxing the constraints of the Holding Company Act will allow for a greater competition of ideas and a greater assurance of matching management competence with project requirements.

The exemptive powers with respect to the FPA are important in order to remove paperwork and filing burdens or constraints on interlocking directors that are found inappropriate or without valid regulatory purpose. Under the bill, FERC is entrusted with the regulatory flexibility to remove impediments caused by these federal statutes in order to give full encouragement to the deployment of clean coal technologies.

The provisions embodied in S. 879 are drafted so as to extend the greatest opportunity for accelerated deployment of demonstrated clean coal technologies. While the funding requested is significant and the regulatory changes proposed are far-reaching, the benefits of the deployment program, as set forth below, are very substantial.

III. PROJECTED BENEFITS FROM CLEAN COAL TECHNOLOGY DEPLOYMENT

Clean coal technologies are attractive because:

- Several new clean coal technologies can meet or exceed stringent environmental requirements of the Clean Air Act, particularly with respect to NO_X emissions;

- these new technologies can provide more flexibility with respect to construction, and reduce the cost of electrical capacity needed in the future over the cost of current technology with scrubbers. The modular feature of several clean coal technologies reverses the economy of scale that has driven utilities to build very large power plants to reduce the dollar per kilowatt cost. These new technologies can yield capital cost savings of 10 to 20 percent depending upon plant size. In addition, controlled modular expansion can be utilized to better match a utility's load growth and reduce utility financing requirements. These reduced costs will directly benefit ratepayers;

- accelerated development, commercialization and widespread use of these new technologies could moderate increases in electric rates, may preserve American mining jobs, will better ensure U.S. industrial competitiveness, will assist in maintaining the deteriorating U.S. infrastructure that supports the electric utility industry, including equipment suppliers and skilled laborers and technicians, and could expand the trade of American coal and technological know-how (without substantial efforts to encourage accelerated development, the users of new clean coal technologies will import these technologies and the U.S. will lose its current lead in developing many of these technologies);

- these new technologies are projected to be up to 30 percent less costly than current control technology that would be used to retrofit existing facilities and, if made available for commercial use, would assist in meeting stricter emission standards if enacted;

- at a demand growth rate of 2% and 50-year average plant lifetimes, in the year 2000 the Nation will need about 100,000 megawatts of new electric generating capacity beyond plants now under construction -- new clean coal technologies need to be widely accepted in order for these technologies to help in meeting that demand;

- current reserves projected into the 1990's give the U.S. a "window of opportunity" during which to develop and incorporate into the utility sector these new technologies that are more cost effective and environmentally efficient than currently-available technology;

- many new clean coal technologies control not only sulfur dioxide emissions but also nitrogen oxide emissions, which conventional technologies do not; and,

- unlike scrubbers, new clean coal technologies do not create wet scrubber sludge, an environmental problem of growing proportions.

A report released recently by the Department of Energy, entitled America's Clean Coal Commitment (February 1987) underscores the importance of new clean coal technologies by comparing the various options for further sulfur dioxide and nitrogen oxide reductions. That report depicted, in chart form, the following:

Options for Further Reduction of SO_2 and NO_X

Install SO_2 Scrubbers	Switch to Low Sulfur Coal	Conventional Coal Cleaning	Innovative Clean Coal Technologies
Advantage:	**Advantage:**	**Advantages:**	**Advantages:**
• Proven method to significantly control SO_2 • Allows existing coal to be used	• Proven method to significantly control SO_2	• Allows existing coals be used • Improves boiler performance	•Much more cost effective in control of SO_2 • May control NO_x as well • Some could be used to reduce emissions, increase plant output, extend plant life – all in one! • Produce usable or easily disposable waste
Disadvantages:	**Disadvantages:**	**Disadvantage:**	**Disadvantage:**
• Very expensive • Reduces Plant efficiency • Produces large quantities of difficult-to-handle sludge	• Would displace many miners of high-sulfur coals • High cost - would result in boiler deratings - premium on low-sulfur coals - would require upgrading of particulate controls	• Can remove only 10-30 percent of the sulfur from most coals	• Full slate of technologies not yet commercially available

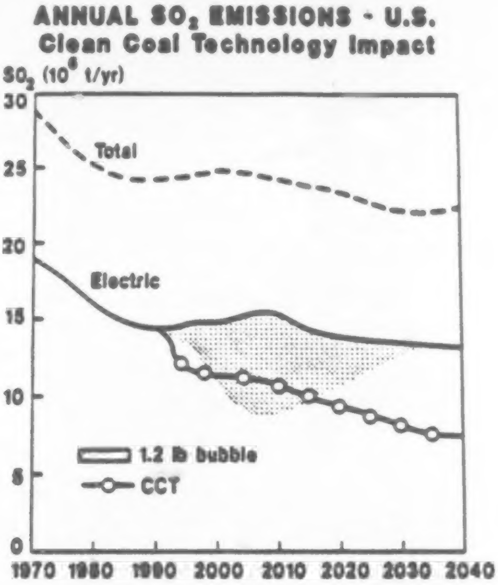
DOE publication:
America's Clean Coal Commitment
February, 1987, page 28

The Electric Power Research Institute (EPRI) has testified before Congressional committees that it costs three times more today in constant dollars to install a kilowatt of conventional coal-fired electric generating capacity than in 1967. Present-day commercial coal-fired technology is at or near the end of its development potential. Consequently, a fundamental improvement in power plant technology is needed -- and promised by improved clean coal technologies -- to respond to the capacity needs, environmental requirements and permitting and siting restrictions facing the electric utility industry. For example, to meet these changing needs, several emerging technologies can be constructed in modules to shorten construction periods, lessen costs and better enable utilities to match growing electricity demand to capacity additions and reduce utility financing requirements. Other benefits to the efficient production of electricity are also possible as various new technology options are developed. EPRI has concluded that new clean coal technologies now under development could reduce significantly the cost of necessary electricity capacity expansion relative to current experience with conventional pulverized coal-fired generating units equipped with scrubbers.

Even more impressive than the cost efficiencies of new clean coal technologies are the significant emission reductions that could be achieved, and sustained, if new clean coal technologies were incorporated into the electrical generating base. EPRI has projected the impact on SO2 emission trends of various strategies under discussion to control powerplant emissions. The basis of the projection is that ALL future generation beyond 1995 would be coal-fired. In this scenario, the growth in coal-fired generation would be more than twice the overall electric energy growth. A finding reached by EPRI analysis is that widespread use of clean coal technologies for new plant and repowering applications can achieve and sustain an increased downward trend in emissions. Acid rain control programs like those currently under discussion, may achieve a rapid initial SO2 reduction, but over a relatively short period of time those emission levels will rise. This increase results from the increased use of coal due to the following:

- retirements of oil and gas-fired generation
- replacement of old coal-fired generation
- new capacity additions, and
- use of currently available control technologies which cannot reach the removal levels of SO_2 (and NOx) projected for new clean coal technologies.

The likely emission trends of various strategies are depicted on the EPRI-derived chart reproduced below.



- Total: Total U.S. emissions trend.
- Electric: Electric power emissions based on 2.3% per year demand growth (after 1995), 60 year fossil plant life and no changes in fuel sulfur content or control requirements (Baseline).
- New CCT Plants: Emission trend resulting if new and repowered power plants utilize advanced clean coal technology -- AFBC, PFBC and IGCC after 1995. The rate of market penetration is strongly influenced by deployment incentives.
- Bubble: Emission trend resulting from state-wide emission control bubble.

Electric Power Research Institute
Before the Clean Coal Technology
Conference
Washington, D.C. (May 7, 1987)

Equally significant are the relative costs of the various strategies. The projected costs of using new clean coal technologies will be 10 to 20 percent lower than the costs that would be incurred if projected capacity additions are met with currently existing technologies.

Quite clearly, the accelerated utilization of clean coal technologies could have enormous positive consequences for our domestic energy supplies, our environment and our economy in general. Enactment of an acid rain control program, as described below, can prevent these benefits from being realized.

IV. CLEAN COAL TECHNOLOGIES ARE NOT LIKELY TO BE DEPLOYED IF ACID RAIN LEGISLATION IS ENACTED

Passage of acid rain legislation mandating major, near-term reductions in SO2 and NOx emissions is likely to stifle clean coal technology development. The capital requirements of compliance with proposed acid rain control legislation would be immense and, inevitably, any funds available for new technological development would be siphoned off to ensure compliance with the regulatory program. Many existing plants might have to be closed on the basis of economic considerations, thus bringing the reliability of today's electric energy supply into question and raising a serious concern over the electric industry's ability to construct new facilities for tomorrow's needs. In reality, any immediate reductions would require widespread use of expensive and troublesome flue gas scrubbing systems because other more cost-effective clean coal technologies are not yet commercially available. The economic effect of such a program could delay the commercialization of these technologies by a full decade.

Those who counsel that clean coal technologies will be commercially available for utilization before major emission reductions are required under current acid rain control proposals are wrong. The demonstration of new technologies simply takes time and, even if demonstration programs are successfully accelerated to the early 1990's and Congress enacts a clean coal technology deployment program, the utility industry will be unable to commit, plan and begin incorporating these technologies into their systems before the turn of the century. It takes approximately three to five years to permit, engineer, design and build a commercial demonstration plant and two more years to conduct testing. To be available for widespread use in the late 1990's, clean coal technology demonstrations must be initiated now. The clean coal technology demonstration program was designed to accomplish this end. The deployment program envisioned by S. 879 is designed to insure and accelerate this process of commercialization.

Proponents of acid rain control legislation also contend that some emerging technologies may be sufficiently demonstrated in the early 1990's so that they could be used to comply with requirements for additional reductions mandated for the mid-1990's. Due to the deployment time frame which was described above, this is not possible. Furthermore, in the process of making expenditures to comply with a control program, the utility industry will use limited funds to meet any mandated emission reductions. There may be little or no funds available to also develop new technologies during the early or late 1990's. At best, mandatory reductions will severely limit the number of new clean coal technologies that will be developed.

Finally, if a utility were to use a new technology without a vendor guarantee or if a utility were to risk incorporating the technology into a system before commercial acceptability is proven and a failure were to occur, that utility might well be judged to have acted imprudently by the governing regulatory body. The risks of such a venture are great and the rewards are small.

Incorporation of a new technology before it is proven is simply not a proper course to pursue. The history of scrubber technology development is a good example of the wrong way to force technology development through imposition of regulatory requirements. According to a case study recently completed by EPRI, flue gas desulfurization scrubber technology was prematurely deployed at commercial scale as a result of legislative and regulatory requirements. The results have been unfortunate. Although industry now has available technology that works, the costs have been great -- to develop and deploy current generation scrubbing technology has involved 50,000 megawatts of electric generating capacity at a total cost to the utility industry and ratepayer of over $20 billion (1987 $) in capital, operating and lost generating capacity costs over the last 15 years. EPRI makes the point that had FGD scrubber technology been developed, as proposed under S. 879, the costs could have been reduced to perhaps $1.0 to $2.0 billion involving about 2,000 megawatts of capacity and with no delay in the time frame to achieve maturity. (See: Attachment D).

The United States has a window of opportunity during which to demonstrate and deploy these new clean coal technologies in a sensible and cost-effective manner. The proposed clean coal technology deployment program provides the incentives to take advantage of this time.

V. CONCLUSION

The accelerated development of clean coal technologies is a sensible, cost-effective approach by which the nation can better ensure energy security while enhancing our economic well-being and maintaining the integrity of the environment.

ATTACHMENT
A

CLEAN COAL TECHNOLOGY COALITION

MEMBERSHIP

May 1, 1987

Allied-Signal, Inc.
Amax Coal Company
American Electric Power Service Corporation
Arch Mineral Corporation
Babcock & Wilcox
Baltimore Gas & Electric Company
Centerior Energy
Central Illinois Public Service Company
Combustion Engineering, Inc.
Consolidation Coal Company
Duke Power Company
Edison Electric Institute
Florida Power & Light Company
General Electric Corporation
General Public Utilities, Inc.
Gilbert/Commonwealth
Illinois Power Company
Indianapolis Power & Light
Industrial Fuels Corporation
Island Creek Corporation
Jersey Central Power & Light Company
Madison Gas and Electric Company
Marietta Coal Company
Metropolitan Edison Company
MHD Development Corporation
Missouri Public Service
National Coal Association
National Lime Association
Northern Indiana Public Service Co. (NIPSCO)
Ohio Edison
Oklahoma Gas & Electric Company
Peabody Holding Company, Inc.
Pennsylvania Electric Company
Public Service Company of Indiana
Public Service Electric & Gas
San Diego Gas and Electric Company
South East Coal Company
Southern California Edison
Southern Company Services
Stone & Webster
The Commonwealth of Kentucky
The State of Illinois
The State of Indiana
The State of Minnesota
The State of Ohio

CLEAN COAL TECHNOLOGY COALITION

The State of West Virginia
TransAlta Utilities Corporation
TRW, Inc.
Union Electric Company
United Coal Company
United Mine Workers of America
School of Mines and Energy Development, University of Alabama
University of Southern Indiana
West Virginia University
Wisconsin Electric Power Company

ATTACHMENT
B

WRITTEN STATEMENT OF THE
CLEAN COAL TECHNOLOGY COALITION
SUBMITTED BY A. JOSEPH DOWD
SENIOR VICE PRESIDENT AND GENERAL COUNSEL
AMERICAN ELECTRIC POWER SERVICE CORPORATION

BEFORE THE

SUBCOMMITTEE ON ENERGY RESEARCH AND DEVELOPMENT
U. S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

April 2, 1987

I. INTRODUCTION

This written testimony is submitted on behalf of The Clean Coal Technology Coalition. The Coalition is organized for the specific purpose of encouraging the demonstration and subsequent deployment of new clean coal technologies. (A list of the Coalition members is attached to this statement.) This statement addresses the need for a Federal clean coal technology deployment program.

I. THE NEED FOR FEDERAL INVOLVEMENT IN THE DEVELOPMENT AND COMMERCIAL DEPLOYMENT OF EMERGING CLEAN COAL TECHNOLOGIES

The United States has recently taken the first steps to bring new and cost effective technologies which use coal in an environmentally acceptable manner to the commercial marketplace. The successful demonstration, followed by rapid and widespread commercial deployment of clean coal technologies, will permit the continued and increased utilization of American coal resources in an environmentally acceptable and cost effective manner.

An adequately funded and technologically diverse demonstration program will allow sufficient demonstration of these new technologies to give the utility industry and their regulatory bodies adequate assurance of their technical capabilities. To ensure that a diverse number of technologies are demonstrated, the Coalition supports the appropriation of $350 million remaining in the Clean Coal Technology Reserve. The purpose of this appropriation would be to implement the second phase of the demonstration program. Upon successful completion of this program the utility industry will then have several additional options with which to meet power needs in the next decade and beyond.

However, regulatory and financial constraints, which accompany the technological uncertainties of first-of-a-kind, immature units, pose serious impediments to commercial deployment of clean coal technologies. Even with the success of the current demonstration programs there is little certainty that the electric utility industry can incorporate these technologies in a timely manner. To ensure the rapid and widespread commercialization of emerging clean coal technologies the Congress and the Administration should consider and adopt a clean coal technology deployment program.

The Clean Coal Technology Coalition (CCTC) has examined a variety of regulatory changes and legislative initiatives which address the critical financial and regulatory issues associated with the deployment of clean coal technologies in the utility sector. While any Congressional initiative to develop a deployment program is likely to be structured as a federal initiative dealing only with policies administered by federal agencies, consideration needs to be given to means by which individual states will become involved in also deploying these technologies. Several suggestions included in this statement could be directed toward encouraging such favorable state action.

II. THE NATIONAL INTEREST IS BEST SERVED BY FEDERAL SUPPORT FOR THE DEPLOYMENT OF CLEAN COAL TECHNOLOGIES:

In the operation of the U.S. economy the process of technology development, demonstration, and commercialization to meet consumer product demand is largely the responsibility of the private sector. In areas such as chemicals and electronics, the process of technology development and deployment in the marketplace has been successfully accomplished by private, risk-taking enterprises seeking to maximize profitability through technology innovation. The major exception to this general rule is in the defense sector where federally funded defense R&D is generally followed by federal support for demonstration and deployment activities even where the major technological risks have been removed.

Unlike other sectors of the economy, the incentive of economic reward for the technology risks taken are not present in the case of regulated companies whose financial performance is significantly affected by direct state and/or federal regulation. When coupled with the substantial technical, financial and regulatory risks associated with the full scale commercialization of first generation clean coal technologies, innovation can be stifled in a regulated environment.

Considering the national importance of providing environmentally acceptable, cost effective electric power, which is generated from vast domestic coal resources, it is critical that a concerted effort be made to reduce or eliminate the disincentives which currently inhibit the commercialization of emerging clean coal technologies. In order for such an effort to be successful, the federal government must assume a leadership role. Such federal initiatives could produce the following national benefits:

1. Use of cost effective and efficient clean coal technologies would provide a basis for minimizing the costs of further emissions

reductions from existing plants should such reductions be needed. Further, the costs of power production from new plants designed to meet incremental demand could also be minimized. Therefore, widespread commercialization of these technologies would benefit both industrial energy users and the general public.

2. Clean coal technologies have the potential to permit the utilization of all types of U.S. coal in an environmentally acceptable manner. Thus, the domestic markets for American coal would be maintained and could be significantly enhanced. Also, when retrofitted to existing facilities, significant reduction in air emissions could be realized in the immediate future.

3. Such technologies may also encourage the export of U.S. coal and American-developed clean coal technologies. Further, the use of our domestic coal resources would help to assure U.S. energy security by sustaining and increasing reliance upon an abundant domestic energy supply.

4. Several of the new clean coal technologies are shop fabricated and modular in design. They can be constructed relatively quickly, thereby reducing construction time and related financing charges. Such technologies provide an attractive option for some utilities to more closely match system capacity additions with actual load growth.

The deployment initiative advocated herein is intended to assure maximum public and private benefits from the investments made in the demonstration program.

III. CURRENT IMPEDIMENTS TO THE DEPLOYMENT OF CLEAN COAL TECHNOLOGIES:

A. The Demonstration of Promising Clean Coal Technologies Is Not Yet Successfully Completed.

Successful implementation of the first phase of the federal clean coal technology demonstration program, as represented by successful execution of the selected technology demonstrations, must be completed to reduce the technology risks inherent in the application of any new technology. A further phase II of the demonstration program directed at retrofit, repowering, or modernization applications must also be completed in order to broaden the technology base of the program and assure maximum public benefit for the public and private funds expended.

B. The Potential of Acid Rain Control Legislation.

If a regulatory program designed to achieve significant additional sulfur emission control is initiated prior to the commercial applicability of advanced clean coal technologies, the technology options available to the utility industry will be limited. The possibility that the Congress will enact more stringent emission control legislation has created an enormous disincentive to the development of clean coal technologies. A regulatory program to achieve compliance with a certain prescribed emission level, within the time frames advocated by some Congressional proponents of acid rain control, will not only be costly but will also preclude the development and deployment of clean coal technologies as utilities will seek to comply with new regulations by utilizing already proven emission control equipment. Unfortunately, existing technologies when applied to near term emissions reduction may result in significant incremental costs to ratepayers over the project life when compared to other, more advanced, alternatives which may not yet be fully commercial.

C. Public Utility Commission Oversight and Prudency Determinations.

The potential for retrospective prudency review of projects involving advanced technologies act to discourage utilities from any such commitments. In addition, utilities have expressed concern that uncertainties associated with future changes in environmental regulations make it extremely difficult to consider technology-based, capital-intensive investments without some level of protection against subsequent "second guessing" by their regulatory commissions. This judgment by a regulatory commission could be made long after substantial commitments and expenditures have been made.

D. Impediments and Disincentives Related to Market Uncertainties.

There are other impediments to the eventual deployment of clean coal technologies that relate to current uncertainties in how critical elements of the marketplace will change in the near future. These market uncertainties are caused by the inability of utility and private analysts to adequately predict what requirements may exist in the future for meeting load growth, for responding to changing fuel prices, and for coping with the ability of independent power generators, such as cogenerators, to compete with existing regulated power companies.

While market-based uncertainties are more properly the responsibility of the utilities and others involved in the use of new technologies, both federal and state governments have a significant influence on some of these issues, and thus there is much that government can do to minimize the difficulty these uncertainties have on utilities.

IV. PROPOSED THREE-POINT CLEAN COAL TECHNOLOGY DEPLOYMENT PROGRAM:

To reduce the risks related to the commercial deployment of clean coal technologies, the Coalition recommends adoption of a three-point clean coal technology deployment program. This program would be designed to assist in the commercialization of a limited number of pioneer clean coal projects. These commercial projects would provide the electric utility industry and others with the evidence needed to choose from a variety of technologies for market-based applications. In order to achieve this stage of technology maturity, it is necessary to assist in reducing the financial and regulatory risks associated with an immature technology. The three-point deployment program, described below, is intended to reduce these financial/regulatory risks.

A. Authorization of a Multi-Year Deployment Program.

A multi-year program, including significant federal funding of amounts in the range of $2.5 to $3.5 billion as recommended by the President and Senator Byrd, respectively, for a period of ten years, should be authorized to encourage the deployment of a specified number of clean coal technology projects. These funds would be in addition to the approximately $400 million already appropriated for the clean coal technology demonstration program and the additional $350 million that should be appropriated out of the Clean Coal Technology Reserve for further demonstrations.

The funding sought under this proposed deployment program should be made available only in that period of time when demonstrations of various clean coal technologies will have been completed. In this way, the deployment program will provide a limited, but direct, economic incentive to those utilities and others willing to undertake the risks associated with commercial-sized, first-of-a-kind, projects using new clean coal technologies. By providing for a ten-year program sufficient time should also be made available to account for the different stages of development of various clean coal technologies. The economic incentives should be specifically directed toward risk sharing or mitigation of risks associated with early commercial-sized projects.

Once the clean coal technology deployment program has been authorized the Congress should appropriate the entire amount in advance but retain the right to determine the maximum appropriate level of government participation in each fiscal year in order to assure that sufficient funds are made available to support the planned technology deployment program. Furthermore, the funds appropriated for the deployment program should be made available to utilities as a grant-in-aid of construction and/or operation. In this way the maximum benefit will be derived from federal participation in the deployment program.

B. Suggested Changes to Existing Regulations.

1. By legislation or changes to existing regulations, the federal government should actively encourage deployment of successfully demonstrated clean coal technologies by adopting regulatory incentives that will provide a participating utility with encouragement and regulatory certainty that treatment before the Federal Energy Regulatory Commission (FERC) will be favorable. Such regulatory incentives like those called for in S.879, introduced by Senator Byrd, would provide much needed and welcomed revisions for the treatment of new technologies.

C. Federal Involvement at the State Level.

In recognition of the fact that the deployment of clean coal technologies can be stymied -- or alternatively greatly facilitated -- by the independent actions of various state regulatory commissions, the Secretary of Energy and the Administrator of the Environmental Protection Agency should utilize the authorities of their respective offices to explain the federal clean coal technology deployment program to the governors and appropriate state agencies and regulatory bodies involved in the regulation of electric utilities.

The Administrator and Secretary should also encourage the appropriate state agencies and regulatory bodies to adopt those regulatory incentives provided at the federal level to encourage the deployment of clean coal technologies.

V. CONCLUSION

Clean coal technologies provide the opportunity for sustaining and increasing the use of U.S. coal, for meeting the future energy needs of this country in an efficient and cost-effective manner, and for protecting our environment. These objectives can be achieved rapidly if the nation will commit to a federally-assisted clean coal demonstration and deployment program.

On March 18, 1987, President Reagan committed to the implementation of a multi-year clean coal program; on March 30, 1987, Senate Majority Leader Robert Byrd introduced legislation, S. 879, designed also to deploy new clean coal technologies. The Congress is urged to consider these proposals and to adopt a program that will benefit our environment and provide the United States with greater domestic energy security.

May 7, 1987

Responses to questions of the Senate Energy and Natural Resources Committee submitted by A. Joseph Dowd on behalf of the Clean Coal Technology Coalition

Follow-up Questions From Senator Ford:

1. Please comment on how the current state and federal regulatory climate impedes the development and deployment of clean coal technologies. How would federal regulatory changes facilitate the commercialization of these technologies?

RESPONSE:

There is a high degree of risk in today's regulatory climate that a retrospective prudency review will be conducted and expenditures already made will be found to have been imprudent. Given the intensity of the regulatory controversies which have developed over the last several years resulting from these restrospective reviews and concerning capital expenditures for new capacity, many utilities have adopted strategic plans which call not only for the least possible capital expenditure, but also for the making of only those capital expenditures that are unquestionably required to satisfy customer service duties. Clean coal technology investments are particularly exposed in this regulatory climate because it is likely that initial investments in clean coal projects will be discretionary expenditures. Thus, the very high technical risks associated with use of a new technology, when coupled with regulatory uncertainty, so concerns the electric utility industry as to deter much investment in new technologies.

The uncertainty associated with changes to environmental regulations also deters development and deployment of these technologies. If, for example, proposed legislation or regulatory changes which impose additional controls upon emissions were adopted, utilities would not have the financial resources also to pursue new technology development. Even the prospect of stricter standards impedes pursuit of these technologies.

Federal regulatory changes that are designed to create more certainty that investments once made can be recovered if projects are prudently pursued would be a powerful stimulus toward assuring accelerated development and deployment of clean coal technologies. Those regulatory incentives set forth in S. 879 are the type of provisions that would facilitate widespread use of clean coal technologies.

2. Would utilities use clean coal technologies on a commercial basis without regulatory changes?

RESPONSE:

Clean coal technologies probably would eventually be commercialized without regulatory changes, but a "business-as-usual" commercialization process is likely to result in the passage of many years before utilities will utilize new clean coal technologies on a widespread basis. Without incentives, it is likely that a pioneering utility will first attempt the demonstration of a given technology and that same utility will then construct the first commercial-scale project. If successful, another utility may then incorporate the technology into its system, and so on until the technology is widely accepted by the utility industry and its regulatory agencies.

Given the current disincentives inherent in rate regulation as presently applied to new, expensive technologies, and the uncertainties associated with environmental regulation, utilities will choose to apply new clean coal technologies sparingly and then only when the technical risks have been minimized by vendor guarantees and utility commissions are convinced that ratepayers are not exposed to undue risks. Of course, to achieve this level of comfort will take an inordinate amount of time or, alternatively, will require assistance in minimizing the risks involved. A properly designed federal program could greatly accelerate commercialization.

3. Does Senator Byrd's bill, S. 879, adequately address the regulatory problems of deploying clean coal technologies? What other incentives do you believe to be necessary to carry these technologies to commercialization?

RESPONSE:

S. 879 adequately addresses the rate regulatory impediments to the deployment of clean coal technologies.

The financial incentives also provided under S. 879 for selected projects are very important in assuring that industry will proceed quickly to the construction of a multiple number of commercial-sized clean coal projects.

Also, certainty with respect to the maintenance of current environmental regulations would provide a strong impetus toward development and deployment of clean coal technologies. The mere threat of changes in environmental regulation tends to stymie utility commitments to new technologies. Rather than use capital to develop or construct new clean coal technology projects, utilities will likely preserve those funds to comply with any new environmental regulations. Importantly, compliance with new regulations would be accomplished by use of existing technologies (e.g. the current generation of scrubbers).

Finally, because approximately 80 percent of utility revenues are subject to regulation at the state rather than the federal level, incentives provided by the states are vitally important. In this regard, it would be exceedingly helpful if the states were to adopt regulatory incentives similar to those prescribed under S. 879 for implementation at the federal level.

4. Please enumerate on the environmental and economic benefits to the U.S. from:

(a) encouraging the development and ultimate deployment of clean coal technologies, rather than the immediate enactment of emissions control legislation?

(b) using the emerging clean coal technologies, rather than using conventional scrubbers?

RESPONSE:

The immediate enactment of emissions control legislation will significantly delay and may preclude totally the development of clean coal technologies. This is so because compliance with the requirements of emissions control legislation similar to that pending in the Senate Committee on Environment and Public Works will be achieved by electric utilities through fuel switching, with its associated social and economic disruption or the use of present day costly sludge generating scrubbers. The very significant expenditures required to comply with proposed emissions control proposals -- estimated to cost as much as $12 billion per year over the remaining life of affected powerplants -- will simply drain the financial resources of those utilities most interested in clean coal technology development.

If clean coal technologies are not allowed to advance because utility resources are diverted to emission control requirements, then future electric demand, which is estimated to exceed current and planned capacity additions by the mid-1990's, will be met using existing pulverized coal technology and current generation scrubbers. The present commercial coal-fired technology is near the end of its development potential. New power generation options must meet increasingly stringent siting and environmental demands while maintaining productivity and at the same time be susceptible to construction in modules over a range of unit sizes so as better to match capacity additions to demand. It is increasingly difficult for utilities to cost-effectively use conventional coal-fired generation capacity to meet these requirements. The consequence of failing to develop new technologies is that ratepayers may very well pay excessive amounts for electricity and utimately the nation will pay in economic competitiveness. The Electric Power Research Institute has testified before the Senate Energy and Natural Resources Committee that clean coal technologies now under development could reduce the cost for necessary capacity additions by more than 50% relative to current experience.

In addition, emerging clean coal technologies will meet environmental requirements more cost-effectively relative to current generation scrubbers. Also, some promising technologies are projected to exceed the emissions reductions now obtained by current generation scrubbers. Thus use of new clean coal technologies will better assure that there will be a sustained reduction in emissions of both sulfur dioxide and nitrogen oxides even though coal utilization is expected to increase dramatically in the next century.

Use of emerging clean coal technologies rather than conventional scrubbers was best described in a recent DOE publication entitled America's Clean Coal Commitment, February 1987. A copy of a chart comparing the costs and the benefits of clean coal technologies to conventional scrubbers is attached to this response. Scrubbers are costly and, in some cases, generate a wet sludge which creates costly waste disposal and environmental problems. Further, scrubbers control emissions of sulfur dioxide only; several new clean coal technologies control not only sulfur dioxide but nitrogen oxide emissions as well.

5. Do you believe that a federal deployment program will assure that utilities and others will undertake the projects necessary to demonstrate the commercial feasibility of emerging clean coal technologies?

RESPONSE:

YES. An adequately funded financial assistance program along with favorable regulatory incentives implemented at the federal and state level will not only provide the best assurance that clean coal projects will be undertaken, but that they will be commercialized sooner than would otherwise be the case. Utilities, and other interested parties, have already demonstrated an interest in the development of these new technologies as evidenced by the substantial response (139 responses) to DOE's solicitation earlier this year for statements of interest to retrofit, repower or modernize existing powerplants with new clean coal technologies.

6. Senator Byrd's bill proposed a $3.5 billion program to be administered over ten years, while the Administration's recent proposal is for a five-year, $2.5 billion program. Please comment on the appropriate timing for a "deployment" program, especially given the various stages of maturity of clean coal technologies.

RESPONSE:

Unlike the proposal envisioned by the Administration request, S. 879 would allow financial incentives for other than electric utility projects. Thus, other industries that use coal would be eligible for the proposed financial assistance program.

Also, it should be noted that expending up to $5.0 billion over a five year period (50-50 cost-sharing between government and industry) in a truly effective manner may not be feasible given other constraints upon the electric utility industry and upon those support services and personnel needed to design and construct these clean coal technology projects (e.g. can sufficient steel be produced?; are there sufficient numbers of craftsmen and skilled laborers available to be dedicated to a series of major construction projects?). Further, some technologies, including the pressurized fluidized bed combustion technology, may simply not be ready for commercialization within the next five years. Thus, in terms of the amount of funding and the period of time for implementation of the deployment program, S. 879 is probably more realistic.

Follow-Up Questions From Senator Domenici:

1. Please comment on the maturity of the various clean coal technologies, especially with respect to the proper timing of a "deployment" program. How can we better coordinate the demonstration phase with the deployment phase, so that we reap the most benefit from these technologies?

RESPONSE:

The majority of clean coal technologies are projected to have completed the demonstration stage by no later than the mid-1990's. While there are differences of opinion as to exact dates, the Department of Energy's recently published study entitled America's Clean Coal Commitment includes information relevant to this question. That information is attached for the Committee's information and use.

The private sector likely will be required to contribute at least fifty percent of the cost of a clean coal technology project under a deployment program. With this type of financial commitment the private sector is in a position to judge the maturity of a technology and presumably will propose only those technologies that are ready for commercialization. Thus, the marketplace should be afforded the opportunity to designate which technologies are ready for the "deployment" program. This can be accomplished by leaving to the marketplace the ability to choose projects. Under this approach it is important that sufficient time be made available so that technologies not yet fully demonstrated are afforded the time required to complete the demonstration stage before commercial-sized projects are undertaken.

Several years may be needed in order to plan for and design a commercial-sized clean coal technology project. This being the case, a deployment program should not be postponed until more technologies have been demonstrated. By enacting the deployment program now, industry will have an opportunity to plan projects, to apply for financial assistance through the deployment initiative, and to acquaint regulators with the technologies so that favorable treatment is forthcoming when the projects are actually undertaken. In other words, it is none too soon to initiate the deployment phase.

2. Some people have proposed that the government's contributions to the cost-shared clean coal projects be offered as grants with no repayment requirements. Yet, from a purely fiscal standpoint, it seems to make good sense to require at least some partial repayment to the Treasury for those projects that realize a profit to the private entity who benefitted from the joint venture. What is your opinion on this?

RESPONSE:

While cost-sharing is appropriate, repayment is not. A repayment requirement is very likely to decrease the level of participation in the program. It should be noted that even if a project is successful, the rates which a regulated utility is allowed to charge are governed on a cost of service basis. For a utility to repay the federal contribution, rates permitted by a utility commission would have to be in excess of the amount required to repay the utility for its incurred costs plus a reasonable return on its investment. Why should that utility's ratepayers be required to repay the federal contribution for a technology that will be available not only to that utility but to all utilities and ratepayers in the country as well? It should be understood that reduction in costs stemming from technology improvements benefit the ratepayers rather than the shareowners/investors. Further, if the technology development involves risk, there is usually no provision for additional benefit to the investors who supply the capital for the risk-bearing installation. And, in fact, should the installation be less than successful, retroactive prudency proceedings which are currently in vogue suggest that risk would be born by the same investor who is unrewarded for having taken the risk. This situation calls to mind the phrase "tails you win, heads I lose."

In the case of retrofit installations, there is no new utility revenue stream to be derived from any clean coal technology installation. Thus, there could be no repayment from additional revenues. In the case of repowering or new capacity, the only revenues that might be available would be those incremental revenues which result from lesser capital costs or greater efficiencies achieved over the next most economical and efficient alternative. These incremental revenues are small or non-existent, particularly in the case of immature technologies which may be more expensive in the near term than the mature versions of those technologies. While these realities exist, a requirement for repayment would simply serve to dampen the enthusiasm for participation in the program. Care should be taken so that this lessening of participation does not occur.

The ability to repay is probably no better for manufacturers of clean coal technologies. The vendor that submits to a utility bid which contains no research and development component costs is likely to be chosen over one that developed the technology and must roll that development cost into his bid. If repayment of the federal portion of a project is required, then the vendor that conducted no research or development can simply obtain the information about the technology from the public record and bid lower than the vendor that must include in his estimate the cost of repayment. That would be a particularly unfortuate outcome. Utility commissions in viewing a company's purchasing practices generally do not make provision for a vendor's research and development expenses. Least-cost is the rule.

3. How well does Senator Byrd's bill, S. 879, address the regulatory problems of deploying clean coal technologies? What other regulatory changes/incentives do you feel are needed to encourage private investment in clean coal technologies?

RESPONSE:

The principal regulatory problems revolve around uncertainty that a utility will be permitted to recover the costs expended and obtain a return upon those costs. S. 879 addresses the principal regulatory problems associated with the deployment of clean coal technologies. Additional regulatory changes/incentives needed to encourage private investment in clean coal technologies involve, most importantly, the adoption by the states of the regulatory incentives contained in S. 879. Also, uncertainties associated with changes to enviromental regulations are very significant. Even the possibility of imposition of further emissions controls is a strong deterrent toward making any commitments that will require substantial funding. Protection of these clean coal technology investments against more stringent future environmental regulations, through the establishment of a "safe harbor", should be given serious consideration.

4. If an advisory panel were established to coordinate and make recommendations on clean coal technology development, what sectors should be represented on this panel?

RESPONSE:

Representation on an advisory panel would, of course, depend upon the purpose of such a panel. If the panel is to assist the DOE in choosing technologies and/or projects to be supported, then a panel of experts knowledgeable with respect to the technologies would be most appropriate. Such a panel should include a strong representation from industry. If the purpose of such a panel is to assist in determining market acceptance of technologies, then representatives from various state regulatory agencies would be appropriate as well as representatives from the user industries.

ATTACHMENT
C

EMERGING CLEAN COAL TECHNOLOGIES FOR RETROFITTING, REPOWERING OR MODERNIZING EXISTING FACILITIES

- 138 PROPOSALS RECEIVED
- 28 STATES, 2 FOREIGN
- TOTAL VALUE EXCEEDS $5.0 BILLION
- 12 EMERGING TECHNOLOGIES OFFERED
  - FLUE GAS CLEAN UP
  - COAL PREPARATION
  - FLUIDIZED BED COMBUSTION
  - ADVANCED COMBUSTORS
  - ALTERNATE FUELS
  - SURFACE COAL GASIFICATION
  - HEAT ENGINES
  - INDUSTRIAL PROCESSES
  - REPOWERING
  - COAL LIQUEFACTION
  - FUEL CELLS
  - MAGNETOHYDRODYNAMICS

Source:
Department of Energy
Before the Clean Coal Technology
Conference
Washington, D.C. (May 7, 1987)

EMERGING CLEAN COAL TECHNOLOGIES FOR RETROFITTING, REPOWERING OR MODERNIZING EXISTING FACILITIES

DISTRIBUTION OF PROPOSALS BY TECHNOLOGY

TECHNOLOGY	NUMBER RECEIVED	TOTAL VALUE* ($000)
FLUE GAS CLEAN UP	49	706,028
COAL PREPARATION	25	409,003
FLUIDIZED BED COMBUSTION	15	1,072,516
ADVANCED COMBUSTORS	13	230,535
ALTERNATIVE FUELS	13	218,141
SURFACE COAL GASIFICATION	11	1,903,200
HEAT ENGINES	3	62,719
INDUSTRIAL PROCESSES	3	57,500
REPOWERING**	3	23,000
COAL LIQUEFACTION	2	71,000
FUEL CELLS	1	6,000
MAGNETOHYDRODYNAMICS	1	400,000
	139	5,159,102

*FIVE SUBMITTALS DID NOT PROVIDE PROJECT COSTS
VALUES REFLECT TOTAL PROJECT COSTS

**SPECIFIC TECHNOLOGIES NOT IDENTIFIED

EMERGING CLEAN COAL TECHNOLOGIES
FOR RETROFITTING, REPOWERING OR MODERNIZING
EXISTING FACILITIES

DISTRIBUTION OF PROPOSALS
BY PRODUCT

	PRODUCT*						
TECHNOLOGY	STEAM	ELECT	COAL WATER FUELS	ENVIR. CONTROL	METALS	SYN NAT. GAS	COAL DERIVED LIQUIDS
ADVANCED COMBUSTORS	3	12					
ALTERNATE FUELS			14				
COAL PREPARATION	1		24				
FLUIDIZED-BED COMBUSTION	5	13					
FUEL CELLS		1					
FLUE GAS CLEAN UP				48			
HEAT ENGINES	2	2					
INDUSTRIAL PROCESSES		2			1		
COAL LIQUEFACTION		1	1				1
MAGNETOHYDRODYNAMICS		1					
REPOWERING	1	2					
SURFACE COAL GASIFICATION	3	10					

*SUBMITTAL MAY PROPOSE MULTIPLE PRODUCTS

EMERGING CLEAN COAL TECHNOLOGIES FOR RETROFITTING, REPOWERING OR MODERNIZING EXISTING FACILITIES

DISTRIBUTION OF PROPOSALS BY USE SECTOR

TECHNOLOGY	SECTOR*				
	UTILITY	INDUSTRIAL	COMMERCIAL	RESIDENTIAL	TRANSPORTATION
ADVANCED COMBUSTORS	12	3			
ALTERNATE FUELS	7	8	3		
COAL PREPARATION	22	13	6	1	1
FLUIDIZED BED COMBUSTION	13	4	3		
FUEL CELLS	1				
FLUE GAS CLEAN UP	48	32	2		
HEAT ENGINES	2	1			1
INDUSTRIAL PROCESSES	2	1			
COAL LIQUEFACTION	2	1	1		
MAGNETOHYDRODYNAMICS	1	1	1		
REPOWERING	2	1			
SURFACE COAL GASIFICATION	11	4	1		1

*SUBMITTAL MAY PROPOSE MULTIPLE USE SECTORS

ATTACHMENT
D

A Case Study of Scrubber Cost and Reliability

The history of lime/limestone flue gas desulfurization (FGD) scrubbing technology in the U.S. provides a valuable but very expensive lesson on the price of exchanging "technology forcing" legislation and regulation for a cooperative development and deployment effort.

Figure 1 describes the typical learning curve associated with the development and deployment of new technology. Development and deployment can be characterized as the process of defining, quantifying and resolving the performance and reliability risks associated with new technology at increasingly larger scale through commercial deployment. The risk costs as a percentage of total are normally highest in the first commercial demonstration facility because of the need to insure the reliable service of the technology. As additional facilities are deployed and gain operating experience the risks are systematically reduced until mature operating confidence is achieved.

Unfortunately, FGD scrubber technology in the U.S. ignored this approach to development and deployment, thus resulting in an exceptional history of cost and inefficiency as indicated by Figure 2. Contrary to sound development practice, FGD scrubber technology bypassed the scale-up process of development and was prematurely deployed at commercial scale as a result of legislative and regulatory requirements. The deployment process also occurred in an adversarial atmosphere where the incentive was on least first cost without adequate understanding of, or insurance against, the performance and reliability risks involved. As a result, this "brute force" approach to development and deployment has involved over 50,000 MW of electric generating capacity at a total cost to the utility industry and rate payer of over $20 billion (1987 $) in capital, operating and lost generating capacity costs during the past 15 years.

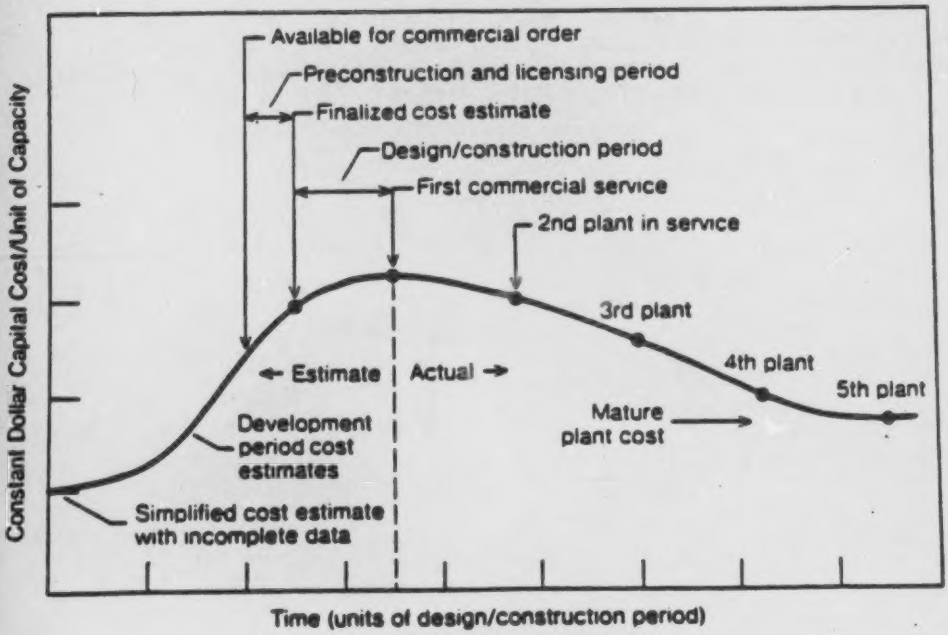
Only now is the technology approaching acceptable reliability, although at an excessive cost in operational risk protection and redundancy which still requires substantial development attention. Figure 2 indicates, for example, the cost reduction which could be achieved through the demonstration and deployment of advanced FGD scrubber technology now in development. In the absence of this initiative, it is unlikely that the cost penalty now associated with acceptable FGD scrubbing reliability can be reduced in the foreseeable future.

Source:
Electric Power
Research Institute
4/12/87

Had FGD scrubber technology been developed and deployed in a more rational and cooperative manner consistent with the pattern of Figure 1, the cost could have been reduced from $20 billion to $1-2 billion involving no more than 2000 MW of capacity and with no delay in the time frame necessary to achieve maturity. In addition, the legacy of poorly performing or obsolete commercial, scrubber installations and the resulting ill-will on the part of the user could have been avoided.

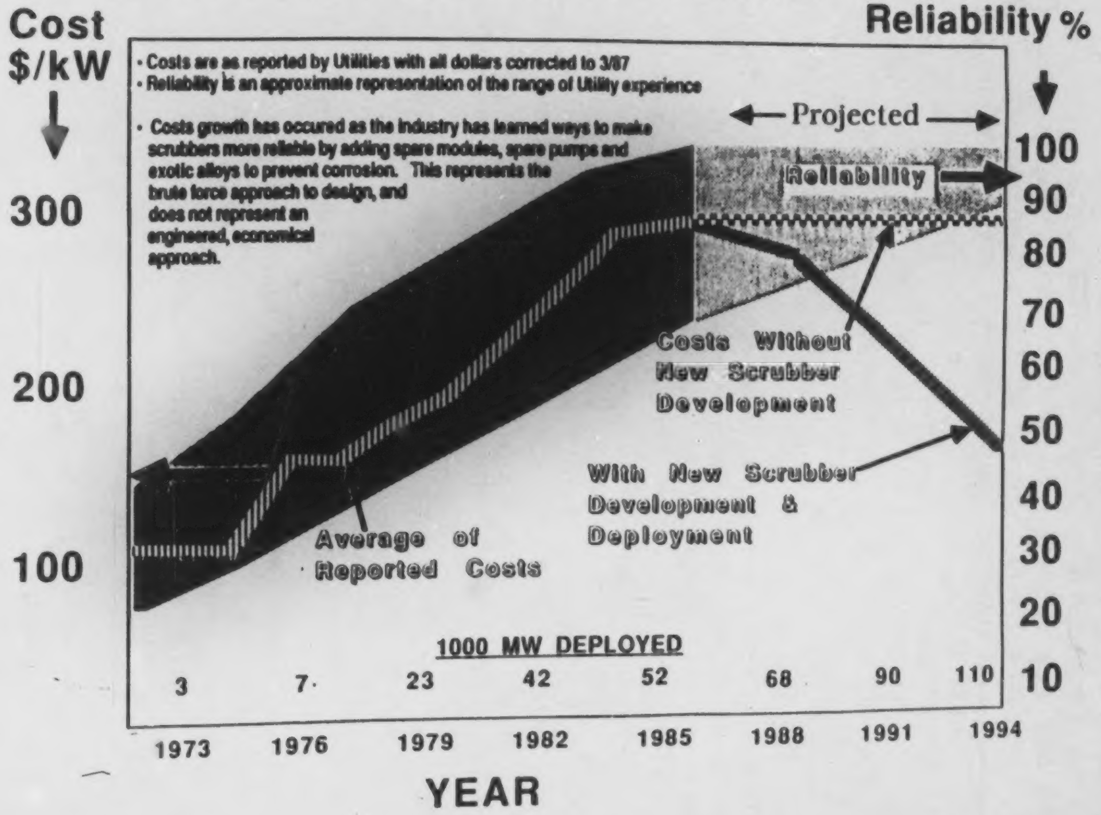
Looking ahead, over the next ten years alone the additional savings resulting from prompt deployment of advanced scrubber technology versus continuing present practice would be about $3 billion just in capital cost. One need look no further than the Japanese experience with FGD scrubbing technology to verify the contrasting success and cost/-effectiveness of the more rational, cooperative approach to risk shared development and deployment.

Figure 1



Cost Learning Curve

Figure 2



Cost and Reliability of Scrubbers

- Costs are as reported by Utilities with all dollars corrected to 3/87
- Reliability is an approximate representation of the range of Utility experience

- Costs growth has occured as the Industry has learned ways to make scrubbers more reliable by adding spare modules, spare pumps and exotic alloys to prevent corrosion. This represents the brute force approach to design, and does not represent an engineered, economical approach.

Cost $/kW
300
200
100
Reliability %
100
90
80
70
60
50
40
30
20
10
Projected
Reliability
Costs Without New Scrubber Development
With New Scrubber Development & Deployment
Average of Reported Costs
1000 MW DEPLOYED
3
7
23
42
52
68
90
110
1973
1976
1979
1982
1985
1988
1991
1994
YEAR

Senator **Ford**. Thank you very much, Mr. White. If I understand your oral statement, you believe the utilities would be hesitant to take any risk to develop new technologies without any Federal action and that you believe that the government should provide both financial and regulatory assistance as we move into these new clean coal technologies.

Is that correct?

Mr. **White**. Senator, I think the experience of the utility industry over the last 10 to 15 years indicates that there is very little to be gained by taking risks in this business and much to lose.

Senator **Ford**. Mr. O'Leary testified basically the same position that you are taking.

This is a problem also for this senator. How many technologies should be demonstrated, well let us put it this way, how many clean coal technology demonstrations do you believe must be successful in order for utilities, their public service commissions, to see this technology as successful?

Mr. **White**. Well, I think as Mr. O'Leary said, that is a difficult question to answer, or really to quantify.

But clearly we need enough that we can demonstrate how to use different kinds of coal across the country, because coal is not of uniform quality, and what might work in one may not work in another.

Now we are working on a project in our own company which we believe will burn almost any kind of coal. But I think you have got to demonstrate at least eight to 10 projects. You have got to show that the commercial size, or that it can be upgraded to commercial size.

And that they work well, that you know how the controls work, that you know that you can burn coal, burn it cleanly, and that it is a reliable operation, that it will give you the kind of reliability that you need to supply electricity 24 hours a day, 365 days a year.

Senator **Ford**. Do you agree with Mr. O'Leary that a commercial size should be at about 250 megawatts? I think that is what he said.

Mr. **White**. Oh, I think at least 250 megawatts. It could be possibly larger than that.

I think that the size of the unit depends to some extent on the size of the system on which you are installing the unit, and the transmission facilities that you have in the location or that you may need.

There are a lot of variables that I think you would have to look at in determining what the proper size of the unit was. But anything less than 250 I would think——

Senator **Ford**. Of course, Ms. Gonze just, I think, testified that GE's latest average utility was 210 megawatts.

Mr. **White**. Yes, sir.

Senator **Ford**. And we have got the fluidized bed combustion operation that is at 160. I wonder why we did not get 50 more megawatts out of it.

Mr. **White**. Well, I think——

Senator **Ford**. It started out about 10 or 15 megawatts, I think, and went from there.

Mr. WHITE. Senator Ford, I think that the way you have a demonstration project where you are trying to demonstrate that the technology will work, you do not want to build a unit any larger than you have to to learn the same things.

Because there will be errors. There will be mistakes made in a demonstration project. The research has been done. We know how the technology, how it is supposed to work. But you have to put it in place and test it and you find things that you certainly did not expect.

Sometimes it has been often called the perils of pioneering, but they are there, and every time you start something brand new you are going to find something that you did not anticipate.

Senator FORD. Well I am a somewhat frustrated representative of a coal state, as you know. I have been trying since 1967 to get something in place. And we do have a pretty good lab in Lexington and we are able to do a lot of testing and that sort of thing and Kentucky put $60 million, $70 million of the state's money in it.

We are part of the fluidized experiment at Shawnee, along with EPRI and several utilities and others. I have been almost willing to give it a shot if it is a white elephant, to try to move on to another process. Some of these make the fuel clean before you burn it. It seemed like to me that it was a pretty good idea.

Let me ask you just a couple more questions. How will the commercial demonstration of these technologies benefit the utility industry, the private sector, and the general public?

Mr. WHITE. Well, I think, Senator, if we can demonstrate a project or a series of projects that indicate that the technology, the new technology will work, that it is cost-effective, that it burns coal cleanly, and is environmentally acceptable, then we have the kind of a plant that utilities generally, all across the country, can say, well, this has been demonstrated.

I can go to the public service commission and I can show that plant X in a specific state works, it works very well, they achieved availability of 80 percent, 80 percent to 90 percent, they achieved a better heat rate than previously achieved in other types of plants. We know what the cost was, and we can demonstrate that we can build that plant here in our state with that kind of costs. And the manufacturers are willing to verify that that can be done.

If we can demonstrate that on a series of plants, then these will be available to all utilities. What we are trying to accomplish here, we have seen enormous increase in costs in this industry over the last 10 to 15 years.

What we could build and supply electricity for with $125 to $150 a kilowatt in the 1960s now costs about anywhere close to 10 times that. I think the figures are mentioned here, together with flue gas scrubbers of the order of $1,500 to $1,600 a kilowatt.

So that is the increase in an order of magnitude. We have seen the same thing happen with fuel. I think there is a popular conception that we do not mind seeing our prices going up. Believe me, sir, that is not true. We are trying to do everything we can to learn to do this in a more cost-effective fashion.

Senator FORD. There has been some suggestion, Mr. White, that the president's legislation and S. 879 could be merged or could be in agreement, and to move forward.

One of the problems is that we talk about, they say that the so-called Byrd legislation is more expensive than the administration's.

But the administration wants to spend $500 million a year for 5 years. Senator Byrd's bill spends $350 million a year for 10 years. Now, can we gain significantly from a slower spendout or rate?

Or do we need to accelerate it and spend more money in a shorter period of time?

Mr. **White**. Well, I think that Senator Byrd's bill addresses the deployment of these technologies. It is going to take some time.

It takes time to license and to build a plant of the order of, we are in the process, my own company is in the process now of building a clean coal technology plant, demonstration plant.

And it is going to take a good while from the time that you obtain the licensing, which can take anywhere from a year to 2 years, and then the construction. On construction you are dealing with somewhat smaller units here, so it is not going to take quite as long.

But I can see 4 or 5 years from the inception of the project to the completion. Then you need a year and a half to 2 years of testing before you can really build a full scale commercial plant.

So these things do take time. You just can not rush them, you can not do them overnight. I have no problem with the 10 years.

Senator **Ford**. Fine, Mr. White. We thank you very much for your testimony. Again, I do thank you for your patience. You have been a valuable witness today and we appreciate your courtesy.

This hearing is hereby adjourned.

[Whereupon, at 5:20 p.m., the hearing was adjourned.]

APPENDIXES

APPENDIX I

Responses to Additional Committee Questions

Department of Energy
Washington, DC 20585

September 14, 1987

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
SEP 14 1987
WASHINGTON, D.C. 20510

OFFICIAL COMMITTEE FILE
PLEASE RETURN

Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

On May 18, 1987, J. Allen Wampler, Assistant Secretary for Fossil Energy, appeared before the Subcommittee on Energy Research and Development of the Committee on Energy and Natural Resources to discuss S. 879, the Clean Coal Technology Act.

Following that hearing, written questions were submitted for our response to supplement the record. Enclosed are the answers to those questions.

If you have any questions, please have your staff call Mark Waggoner on 586-4277. He will be happy to assist.

Sincerely,

Robert G. Rabben
Assistant General Counsel
for Legislation

Enclosures

Celebrating the U.S. Constitution Bicentennial — 1787-1987

ANSWERS TO POST-HEARING QUESTIONS
RELATING TO THE
MAY 18, 1987, HEARING
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

WITNESS: J. ALLEN WAMPLER

ASSISTANT SECRETARY FOR FOSSIL ENERGY

U.S. DEPARTMENT OF ENERGY

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 1: In a recent hearing before the Environment & Public Works Committee, EPA Administrator Thomas suggested the lack of an "acid rain emergency." Do you agree with his assertion?

- Please submit scientific evidence which backs up this conclusion.

Answer: Findings from the interagency research conducted under the National Acid Precipitation Assessment Program (NAPAP) continue to support the earlier conclusions that known damage levels potentially attributable to acid rain are small relative to the total resource that could be affected and that no rapidly developing damage trends exist. Supporting information is available in the "New Findings" section of the Joint NAPAP/ Canadian Research and Monitoring Coordinating Committee (RMCC) report published February 27, 1987 (attached) and the June 30, 1987, NAPAP 1986 Annual Report (see especially the Executive Summary).

Therefore, Administrator Thomas' statement that there is not an acid rain emergency is valid and well supported by our current knowledge. However, there continue to be areas of uncertainty that require resolution. In these areas, the available information suggests that any detrimental effects would not show rapid change under existing and projected levels of emissions. When NAPAP completes its final assessment in 1990, the majority of the critical uncertainties should be sufficiently resolved to permit the Administration and the Congress to determine what, if any, additional control or mitigation steps are necessary.

issued for each project a "Memorandum to the File" to fulfill DOE's responsibilities under Section 27.3 ("Post Selection NEPA Review") of the Program Opportunity Notice (PON). Enclosed are copies of the "Memorandum to the File" for these three projects. The site-specific NEPA documents to be prepared under PON Section 27.3 for the remaining six projects will be submitted for the record as soon as they are finalized.

JOINT REPORT

TO

BILATERAL ADVISORY AND CONSULTATIVE GROUP (BACG)

Status of Canadian/U.S. Research in Acidic Deposition

Prepared by:
U.S. National Acid Precipitation
Assessment Progam (NAPAP)
Canadian Federal-Provincial Research
and Monitoring Coordinating Committee (RMCC)

February 25, 1987

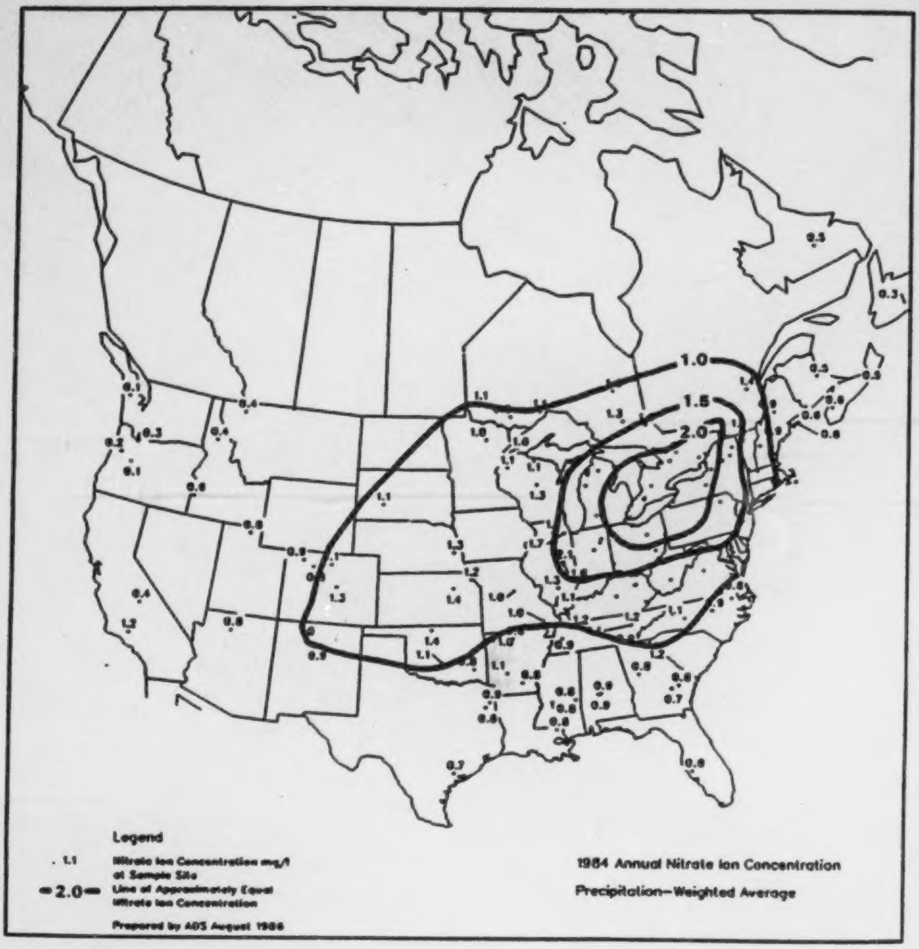
Errata Sheet for
February 25, 1987
Joint Report to the Bilateral Advisory and Consultative Group: Status of Canadian/U.S. Research in Acidic Deposition

1. Page iv - Table 11 should be listed as Table 12; Table 12 should listed as Table 11.

2. Executive Summary Page - 2, line 30 change the number 8500 to 8000.

3. Figure 23. An improved version of a map showing nitrate deposition is provided attached as errata Figures 1 and 2.

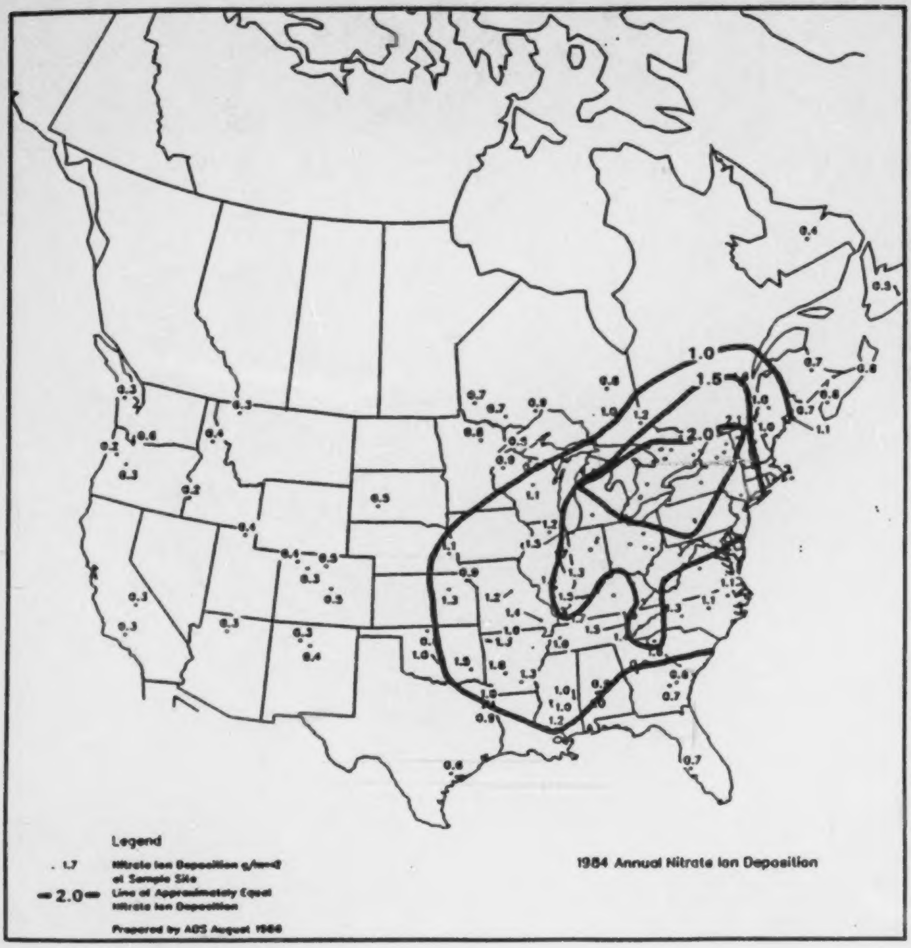
4. NF-18 line 4 should refer to Figure 23 rather than to Figure 24.


1.0
1.5
2.0
Legend
. 1.1 Nitrate Ion Concentration mg/l at Sample Site
2.0 Line of Approximately Equal Nitrate Ion Concentration
Prepared by ADS August 1986
1984 Annual Nitrate Ion Concentration
Precipitation—Weighted Average

Errata Figure 1: 1984 Annual Precipitation-Weighted Nitrate Ion Concentration (mg/l) Spatial Pattern.

Reference:

U.S.-E.P.A. 1986 Annual Data Summary by A.R. Olsen and EPA-600/4-86/033. December, 1986.



1.0
1.5
2.0
Legend
. 1.7 Nitrate Ion Deposition g/m2 at Sample Site
2.0 Line of Approximately Equal Nitrate Ion Deposition
Prepared by ADS August 1986
1984 Annual Nitrate Ion Deposition

Errata Figure 2: 1984 Annual Nitrate Ion Deposition (g/m^2) Spatial Pattern. Multiply by 10 to determine kg/ha.

Reference:

U.S.-E.P.A. 1986 Annual Data Summary by A.R. Olsen and EPA-600/4-86/033. December, 1986.

February 25, 1987

Mr. John D. Negroponte
Assistant Secretary
Bureau of Oceans, International
Environmental and Scientific Affairs
Room 7831 Department of State
Washington, D.C. 20520

Mr. Donald W. Campbell
Assistant Deputy Minister
United States Branch
External Affairs
125 Sussex Drive
Ottawa, Ontario K1A 0G2

Dear Messrs. Negroponte and Campbell:

At the last meeting of the Bilateral Advisory and Consultative Group (BACG) in Ottawa on June 17, 1986 you charged the RMCC and NAPAP to periodically provide a statement of progress in the scientific research related to transboundary air pollution.

Enclosed is the first Joint Report on the Status of Canadian/U.S. Research in both Canada and the U.S. in Acidic Deposition. It encompasses current research programs, the specific response by the U.S. to the research recommendations of the Special Envoys, the current and planned joint research projects, and a list of "new findings" subsequent to the assembly of information for the Special Envoys' report. It is anticipated that each of the future NAPAP/RMCC reports will update the list of new findings.

Where lack of agreement exists on a topic, we have agreed that it shall become an active subject for further discussion and/or planning of additional research. We believe this process of communication as well as the ongoing production of new information will steadily enlarge the scientific data base in the causes and effects of acidic deposition, and thereby enhance the potential for rational and efficient control strategies.

Trusting this is responsive to your request,

Sincerely,

J Laurence Kulp
J. Laurence Kulp
Director of Research
U.S. National Acid Precipitation
Assessment Program

HLFerguson
Howard L. Ferguson
Assistant Deputy Minister
Environment Canada
Cochair, Federal Provincial Research
and Monitoring Coordinating Committee

JWGiles
J. Walter Giles
Associate Deputy Minister
Ontario Ministry of the Environment
Cochair, Federal Provincial Research
and Monitoring Coordinating Committee

February 25, 1987

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26. Decrease of growth in pine from Georgia over three survey periods. NF-18

February 25, 1987

EXECUTIVE SUMMARY

This is a joint report by the U.S. National Acid Precipitation Assessment Program (NAPAP) and the Canadian Federal-Provincial Research and Monitoring Coordinating Committee (RMCC), the coordinating bodies for the scientific research directed toward understanding acidic deposition related to transboundary fluxes of SO_2, NO_x, VOC and their associated acids and oxidants. Its purpose is to summarize for the BACG the ongoing research program of both countries, including research specifically aimed at issues raised in the Envoys report, the joint projects, and the significant new additions to the scientific findings.

Joint research projects were initiated in the 70s. Currently, there are 21 joint projects (Table 1) distributed in areas of Forest Effects, Aquatic Effects, Atmospheric Transport, Deposition Monitoring, and Effects on Materials. Particular emphasis has been placed on intercalibration of sampling and laboratory analysis so that results are consistent across North America. Mutual support and full exchange of data exists in areas of acidic deposition and air quality monitoring, cloud chemistry at high elevation in the Applachian mountain chain, material samples at test sites, national emission inventories, cross-continent tracer experiments, and surface water chemistry surveys.

At the joint RMCC/NAPAP meeting in Washington, DC on November 25, 1986, several potential new joint projects were identified: (1) Cause of sugar maple decline, (2) Chemical composition of ground level fogs, (3) Intercomparison of sites for dry deposition. Joint participation in the formal peer reviews of completed or continuing programs was established.

The major part of this report consists of a summary of new scientific information developed subsequent to the data base used in producing the Special Envoys Report. Highlights of the "New Findings" are as follows:

1. Emissions - In the eastern states bordering Canada, which make the largest contribution to transboundary flux the emissions of SO_2 have declined by about one million tons (10%) from 1980 to 1985.

   SO_2 emissions in eastern Canada decreased by 45 percent from 1970 to 1984 in response to a series of increasingly stringent emissions regulations.

2. Atmospheric Chemistry - Studies around Philadelphia, PA during selected storm events showed that nitrate and sulfate deposition were significantly elevated downwind from the urban area and that low concentrations of oxidants in winter limit the production of sulfate and nitrate from SO_2 and NO_x.

3. Atmospheric Modeling and Transport - Large-scale experiments with inert tracers showed that simple trajectory long-range transport models can reproduce the movement of air parcels well for at least the first 24 hours in the absence of storms.

   Canada and the U.S. evaluated the performance of eleven linear sulfur atmospheric chemistry models. In comparing observed deposition with predicted patterns, the models did not reproduce secondary peaks, and displaced the maxima by several hundred kilometers. However, given the low discriminating power of the test, the differences between observed and predicted patterns were generally not significantly different over most of the area.

4. Deposition Monitoring - On the basis of preliminary analyses of CANSAP-APN and NADP data for the eastern half of the continent, changes in anthropogenic emissions during the period 1979-1982 are not readily apparent; concentration changes from year-to-year occur concurrently in both anthropogenic and natural constituents and are thought to be more strongly affected by meteorological rather than emissions changes during this period.

Preliminary estimates suggest that dry deposition ranges from 14 to 26% of the total deposition of sulfur in remote locations. The contribution may be up to 40% nearer emission sources.

5. Cloud Chemistry - Wintertime cloud chemistry at Whiteface Mountain, NY shows low concentrations of oxidants leading to higher SO_2 and NO_x and less acid than in the summertime. Summer hydrogen peroxide levels are in the thousands of parts per billion and may account for most of the acid formation.

Ozone concentrations in clear air at Whiteface Mountain are about twice as high in May-June as in December-January.

6. Aquatic Effects - Sulfate and acidity decreased in twelve Nova Scotia and eight Newfoundland rivers between the early 1970's and the early 1980's consistent with decreased emissions in the eastern U.S. and Canada.

From the early 1960's through 1983, two benchmark streams in the northeast showed sulfate concentrations down and alkalinity up. In addition, regression analysis suggests that a reduction in regional emissions would lead to a nearly proportional reduction in stream sulfate yield.

The Eastern U.S. Lake Survey of areas most likely to be sensitive to acidic deposition has been completed. In the northeast, the highest percentage of lakes with pH <5.0 occurs in the Adirondacks (10 percent of number of lakes, 1.6 percent of lake area). The Western Lake Survey found only one acidic lake fed by an acidic hot spring.

The Alk/Ca + Mg ratio will decrease from a value near unity for a lake unaffected by atmospheric deposition to zero or less as the waters are acidified. Analysis of surface water chemistry from about 8500 lakes in eastern Canada shows ratios varying from less than zero to 1.0 in lakes from western Ontario eastward and south of 52° latitude. This deficit results from the presence of sulfates. Several studies in Canada and in the U.S. have shown that natural organic acids cannot account for the acidic status of these lakes.

Over the past 50-60 years, no significant change in alkalinity in tested lakes in New Hampshire (an area of relatively high acidic deposition) is apparent and average pH may have increased. During this period, the pH and alkalinity of Wisconsin (an area of relatively low acidic deposition) lakes have increased significantly. In the Adirondacks (an area of relatively high acidic deposition) pH and alkalinity have remained constant or decreased.

Water chemistry in the Sudbury area has shown major decreases in sulphate concentrations and substantial increases in pH and alkalinity since the early 1970's when large local SO_2 emission reduction programs were implemented.

In concert with these emission reductions, historical data at Joe Lake near Sudbury spans a complete cycle of fish extinction from acidification in the 1950's to nearly full recovery by 1984 following stocking in 1977. This demonstrates recovery potential for even highly acidified lakes.

An experiment in Norway has shown rapid response (1 year) of a very sensitive acidified watershed when deposition is reduced.

Recent measurements of shallow groundwater (less than one metre) have shown acidification by mineral acids.

7. Crops - Dose/response experiments in laboratory and field grain crops show no significant reduction in yield over a wide variety of species when exposed to simulated acidic deposition in the ambient range experienced in eastern North America.

In contrast, for an average 7 hr growing season concentration of ozone of about 90 ug/m^3 (45 ppb) over the eastern U.S. and southeastern Canada, all species tested including major grains and vegetables show a reduction in yield over controls which were exposed at 40-50 ug/m^3, (20-25 ppb).

8. Forests - Results of a controlled study on seedlings of tulip poplar, white oak, and virginia pine using simulated acid rain over three growing seasons at pH 5.7, 4.5, 4.0, and 3.5 showed no significant response in growth, photosynthesis or morphological properties.

Another study exposed eleven species of deciduous and coniferous seedlings during their first five weeks from germination to simulated rain at pH 5.6, 4.6, 3.6, and 2.6. (Author's Interpretation: Treatment with pH $\leq$ 4.6 rain was sufficient to induce statistically significant growth reduction and morphological changes in coniferous seedlings). (U.S. Interpretation: Except at pH of 2.6 there were no significant effects on cumulative germination, survival or above ground biomass. Effects on some morphological characteristics were ambiguous at pH 3.6 and 4.6).

Seedlings of four tree species (hybrid poplar, sugar maple, northern red oak, and eastern white pine) common in northeastern U.S. were exposed to a range of ozone levels up to 280 ug/m^3 over the growing season. This resulted (Figure 22) in reductions in net photosynthesis of 10 to 40 percent over growth under an assumed background level of about 50 ug/m^3.

Surveys of red spruce in New England and New York have shown some retardation in growth in the low elevation forests and serious decline and visible damage on spruce trees above cloud base. There is a major sugar maple dieback in Quebec and to a lesser extent in Ontario. Surveys have been carried out in Quebec and it is noted that "there were very few cases of maple stands totally exempt of damage in some form or another". Some damage was observed in 40% of the 533,582 hectares surveyed. The Quebec surveys indicate that dieback of sugar maple occurs throughout its range and within different forest types and on several different sites. Surveys of beech, red maple and yellow birch in New Brunswick and parts of Nova Scotia bordering the Bay of Fundy have shown decline symptoms. Southern pine in the southeastern piedmont region have shown reduced growth in recent decades. Natural stresses and air pollution have been proposed as causative factors for all three observations, and experiments have been planned to test these hypotheses. At present, these survey observations cannot demonstrate whether or not acidic deposition is a factor.

9. Materials - While exposure to the atmosphere clearly causes corrosion of various materials, and acids should accelerate the process, these relationships have not been quantified.

Long-term exposures of galvanized steel specimens show runoff losses of zinc that are dependent on total acid deposition.

February 25, 1987

I. INTRODUCTION

BACKGROUND

In March of 1985 President Reagan and Prime Minister Mulroney appointed Special Envoys, Drew Lewis and William Davis, to assess the international environmental problems associated with transboundary air pollution and to recommend actions that would help to solve those problems. The Joint Report of the Special Envoys on Acid Rain was submitted in January, 1986. The report included a perspective on the understanding of the scientific issues held by the two nations. The President and the Prime Minister endorsed the report at their summit in March, 1986, and have since established the Bilateral Advisory and Consultative Group on Transboundary Air Pollution (BACG) to pursue the work of the Special Envoys and to report to the President and the Prime Minister.

To prepare for its December, 1986 meeting, the BACG asked the National Research Coordinating Organizations i.e., the U.S. National Acid Precipitation Assessment Program (NAPAP) and the Canadian Federal/Provincial Acid Rain Research and Monitoring Coordinating Committee (RMCC) to report to them on new scientific findings, current research programs, and joint U.S.-Canadian projects. This report responds to that request. The first part describes current research programs and the general response of the U.S. NAPAP and Canadian RMCC to the research recommendations of the Special Envoys Report. The second part summarizes existing joint projects and new projects currently in the planning stages. The third part describes scientific results that have become available since the Special Envoys Report and for which consensus on their interpretation exists. Conclusions from reports that have not found agreement or for which research is incomplete will be on the continuing agenda of the NAPAP/RMCC in an attempt to plan and execute sufficiently definitive experiments/observations to achieve agreement.

Numerous research programs are being conducted worldwide on the effects of air pollutants. In Canada, the research program is coordinated by the RMCC (the Federal/Provincial Acid Rain Research and Monitoring Coordinating Committee). Federally funded research on acidic deposition within the United States is coordinated by the National Acid Precipitation Assessment Program (NAPAP). NAPAP activities are coordinated by the Office of the Director of Research (ODR). NAPAP and RMCC representatives meet at least annually to facilitate coordination of research. Joint research programs are carried out between the countries and there is considerable exchange of scientific information via workshops, conferences, and reviews of the national programs. Canada will participate in NAPAP's review of aquatic and terrestrial effects research programs in 1987.

TERMINOLOGY

Air pollution can produce undesirable results by interacting with humans, animals, plants, soils, materials, and aquatic ecosystems. The purpose of this section is to ensure common use and interpretation of specific terminologies relating to air pollution and its effects in the following discussion. Emissions of several kinds of compounds (primarily SO_2, NO_x and VOCs) can result in acidic precipitation. Oxides of nitrogen (NO_x) and volatile organic compounds (VOCs) interact in the presence of water vapor and sunlight to form oxidants. Sulfur dioxide (SO_2) and NO_x can be oxidized by these oxidants in the atmosphere to sulfuric and nitric acid.

ACIDIC PRECIPITATION is the term used to describe sulfuric, nitric, and organic acids falling in rain, sleet, or snow.

WET DEPOSITION includes acidic precipitation as well as heavy metals, alkaline compounds, and other constituents of rain, sleet, and snow.

DRY DEPOSITION is the deposition of gases and particles on surfaces. It includes reaction of gases such as ozone, sulfur dioxide, and nitrogen dioxide with surfaces, and adherence of particulate matter which can include alkaline compounds and sulfate.

OCCULT DEPOSITION describes the interaction of fog or clouds on surfaces. Cloud or fog water droplets can contain high concentrations of sulfuric or nitric acid as well as high concentrations of oxidants such as hydrogen peroxide.

ACIDIC DEPOSITION includes the acidic components of acidic precipitation, dry deposition, and occult deposition.

ATMOSPHERIC DEPOSITION includes the deposition of any air pollutant ranging from sulfuric acid to oxidants to heavy metals to organic compounds or any other substance transported through the atmosphere and deposited on the earth's surface whether in wet, dry, or occult forms.

OXIDANTS include ozone, hydrogen peroxide, PAN (peroxyacetylnitrate), and the hydroxyl radical. Oxidants are important not only because of their pivotal role in atmospheric chemistry, but also because they are biologically potent.

AIR POLLUTION includes all pollutants in the atmosphere whether or not the compounds are deposited on the earth's surface or have their primary effect as a result of deposition on surfaces.

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DOC 10

February 25, 1987

PART 1. RESEARCH

Research programs in Canada and the United States are conducted to reduce uncertainties associated with the causes and effects of acidic deposition. The resulting reduction in uncertainty provides policy makers with the scientific information which can result in more accurate descriptions of resources which may be protected as a result of any additional regulation. Thus the research programs described below for both the U.S. and Canada reflect extensive discussions between policy makers who state their needs for information and researchers who state their ability to produce information.

The following section describes the research programs of the United States and Canada including Canada's response to the Envoy's research recommendations, the response of the U.S. program to the six recommendations for research contained in the Special Envoys report, and a list of cooperative projects between the two programs. This description of research does not include the substantial provincial, state and private research programs.

1.1 CANADIAN RESEARCH PROGRAM

Introduction

The Canadian research effort on the causes, formation, and effects of acid rain is carried out by Federal, Provincial and private sector institutes. The total cost is approximately $30 million per year. A description of most projects is provided every few years. The latest compilation, published in February 1986, described over two hundred projects (Canadian Research Catalogue on LRTAP and Acid Rain, Environment Canada, Downsview, Ontario).

The purpose of this section of the report is to describe the principle research objectives of the Canadian Federal program. The achievement of these objectives will advance our understanding of the acid rain issue in key areas and ensure the long-term assessment of the Canadian SO_2 control program. Specific details concerning individual projects are not provided.

The design of the Federal Research program takes account of two important considerations.

a. Canada has initiated a control program for SO_2 designed to reduce domestic emissions by 50% by 1994 based on 1980 levels.

b. The Envoy Report made six specific research recommendations to the U.S. and Canadian Governments.

The program therefore, is designed to evaluate the environmental consequences of domestic SO_2 control and to strengthen areas of research in response to the Envoy Report.

Objectives

1. Continue a long-term monitoring program to assess the effects of changes in emissions.

   The Program includes national networks to determine atmospheric deposition, lake chemistry and biological status, and forest health, including soil status. There will be a subset of stations with permanent integrated (i.e., multidisciplinary) monitoring programs.

2. Refine the sulphate target loading.

   Target loadings or critical loadings for sulphate deposition have been developed for eastern North America based on both empirical observations and theoretical considerations (MOI, Canadian Assessment Document, Nordic Council Report on Target Loadings).

   Using empirical observations in Eastern North America which are supported by theory, Canada adopted a target loading value of 20 kg/ha/yr of SO_4 in wet deposition as being protective of all but the most sensitive surface waters.

   Simulation model calculations indicate that acidification will continue in Eastern Canada in highly sensitive waters subjected to a wet deposition of 20 kg/ha/yr and that a reduction to 12 kg/ha/yr of total excess sulphate deposition may be required to protect the most sensitive surface waters (Canadian Assessment Document - Part 3 - Aquatic Effects).

   Further evaluation of survey data and theoretical models will be carried out to refine these target loading values.

3. Document the biological effects of acidification stress in lakes.

   The current aquatic program has largely resolved the chemical aspects of acidification by sulphate. There are still some deficiencies in knowledge regarding the biological quality of lakes under various degrees of stress (i.e., those which have lost some but not all of their alkalinity and have a lower pH than under pristine conditions), particularly with regard to the rates of change. Continued biological studies are needed to determine the present extent of environmental loss in Canada and predict the likely conditions under the various control programs.

4. Determine how air pollution affects forests.

   Forest decline is a major problem in eastern Canada and the contribution of air pollution, must be determined. Scientists appear in agreement that air pollution is a contributor to the forest declines observed in eastern North America. There are two preferred hypotheses under consideration.

   a. Damage caused by long-term subacute concentrations of pollutants. Experiments in northeastern U.S. were conducted in which trees were enclosed in open-top chambers and exposed to ambient air fed through charcoal filters. Over the 3-year experiment, the cumulative dry biomass production of the seedlings was 20-35% higher in the chambers with filtered air compared to the chambers with unfiltered air and ambient conditions. The ambient ozone concentrations during April through September ranged from 40 to 65 ppb for each of the 3 years of the experiment. These results imply that ambient air quality, particularly ozone, is causing a significant stress on trees. Chevone, B.I. and J.M. Skelly and Y.S. Yang Aquno Ser Bot. 19 pp. 198-207.

b. Acid deposition leading to soil acidification including nutrient deficiencies, particularly calcium, magnesium, and potassium. This appears to be gaining considerable support, most notably from an increasing understanding of the actual chemical changes in the soils and from field experiments in which the nutrients are added back and the trees regain their health.

Much of the information on soil chemistry, nutrient leaching, and the role of nitrogen in soil processes comes from the detailed calibrated watershed studies and biogeochemical study plots across the country.

The research will determine the relative contribution of deposited nitrogen and sulphur compounds to forest stress.

5. Complete and test the Eulerian Model.

Lagrangian models have been used in the development of the Canadian control program. Eulerian models are being developed in Canada (with the participation by the FRG) and the U.S. to comprehensively simulate the processes of transport, transformation and deposition of acidifying pollutants on an episodic basis. These models will contain more sophisticated atmospheric chemistry and more precise transport terms than existing models.

The Canadian Eulerian model will be completed and tested. It will be used in future control scenario evaluations for nitrogen, ozone and possible second-phase sulfur emission control. Canada and the U.S.A. are proceeding with a joint field calibration and verification project designed to evaluate national Eulerian models. This work is included in the listings of joint Canada-U.S. research in this report.

6. Complete the human health/ambient air quality relationship studies.

The long-term objectives of the health sector of the program are 1) to assess the risk to health posed by airborne pollutants which are subjected to long-range transport; 2) to determine the health hazard posed by the secondary effects resulting from the deposition of acidic substances; and 3) to monitor the influence of abatement programs on human health.

Three approaches have been taken.

a. The Portage-Tillsonburg study was a cross-sectional study to assess the respiratory health effects of chronic exposure to transported air pollution. Respiratory health questionnaires and lung function tests were administered to over 1,400 school children, aged 7 to 12 years, half residing in a rural community in a low pollution area (Portage la Prairie, Manitoba) and half living in a rural community in southwestern Ontario (Tillsonburg) where transported pollution levels are among the highest in Canada. After adjusting for confounding variables (such as parental smoking and socioeconomic status), data analysis indicated that children living in Tillsonburg had statistically significant decrements in lung function parameters (2%) compared to those residing in Portage. Children in Tillsonburg also had a higher prevalence of inhalant allergies and some respiratory symptoms. Monitoring data indicated that levels of SO_2, respirable sulphates, and respirable nitrates were significantly higher in Tillsonburg than in Portage la Prairie.

During 1985 and 1986, a larger epidemiological study was initiated to validate these findings.

b. The second group of studies was designed to assess the acute health effects of short-term exposure to elevated levels of transported air pollutants.

In 1983, 52 children, 23 of whom were diagnosed asthmatics, participated in an acute effects study at a summer camp. Data analyses indicated that short-term decrements in lung function were associated with periods of elevated levels of transported air pollutants.

During the summer of 1986, another camp study was performed over six weeks, utilizing a similar design but expanding the health and monitoring parameters. One hundred and twelve girls at Girl Guide summer camp in southwestern Ontario, an area subjected to high concentrations of transported pollution, participated. During the study period, ten air pollution "events" occurred (events were defined as 0_3 concentrations greater than or equal to 0.080 ppm, and/or fine particle sulphates greater or equal to 15 ug/m^3 for four or more consecutive hours). Seven of these events were of short duration (7-12 hours). The remaining three events each lasted from 2-1/2 to 3-1/3 days. The data are currently being analyzed in conjunction with health measurements.

c. An animal toxicology program was initiated in 1986 to complement epidemiological and monitoring studies. During the 1986 summer camp study, three bulk samplers were used to collect fine fraction acid aerosols in southwestern Ontario. The acute and relative toxicities of these aerosols are currently being investigated in Syrian golden hamsters, using intratracheal instillation as the mode of administration. Histological, biochemical, and immunological parameters are being examined.

Data from both epidemiological and animal toxicological studies will be assessed to evaluate the health responses to transported air pollutants.

Future Research

Future research plans include an expansion of our animal toxicology program in order to investigate more quantitatively the toxicological effects of acid aerosols, ozone, and respirable particulates and the continuation of epidemiological studies.

An investigation of indoor air quality and possible variation among communities in indoor air pollutant levels is also planned in order to ascertain that any observed chronic health differences associated with transported air pollution are not due to differences in indoor air contaminants.

Studies to refine the characterization of the physical and chemical properties of acid aerosols and their spatial and temporal variation in ambient air are also being initiated.

7. Maintain LRTAP materials corrosion program.

   Canada has provided a materials effects station in an area of low air pollution as a "background" station for a North American joint Canada/U.S. program. This project is included in the section on cooperative research in this report. Recent studies have indicated that time of wetness and in situ corrosion rates are critical considerations when assessing the incremental impact of air pollution on material durability. The current study of corrosion rates over a single urban structure focusses on time of wetness and material response at different sites on the building. A second building in another large urban area will be instrumented.

8. Redirect socio-economic studies.

   Studies will be carried out on the social and economic consequences of control programs.

9. Continue studies of air-borne heavy metals and organic compounds.

   Heavy metals appear to be transported in the atmosphere and in addition, they can be mobilized by acid conditions. Organic compounds are also transported long distances. Further studies are needed on the extent and environmental consequences of both metals and organics.

1.2 UNITED STATES NATIONAL PROGRAMS

1.2.1 Responses to Special Envoys research recommendations

The report of the Special Envoys included recommendations for research of "special value to decision makers in guiding the development of environmental policies." They recommended that research be actively pursued in six areas. Their recommendations and a discussion of the NAPAP activity in each area are provided in this section.

Deposition Monitoring

Recommendation:

Standard, accurate methods to measure dry deposition should be developed and monitoring networks deployed. The networks should be of sufficient size and adequate statistical design, and implemented with adequate quality assurance and quality control procedures, in order to enable researchers to measure total acid deposition for sensitive areas across North America.

To develop a data base for determining dry deposition, standardized equipment (Canadian filter packs ozone monitors, meteorological equipment) will be installed at 30 deposition monitoring sites, beginning in late 1986. Rigorous quality assurance and quality control programs are being developed. The monitors are being scientifically sited based upon statistical techniques which will assure that monitors are sited in a fashion to determine both maximum deposition and gradients. Six pilot monitoring stations are in place and have and will continue to produce information helpful for deploying and evaluating a monitoring network.

The network will be designed primarily to evaluate atmospheric models and secondarily, to describe exposure of forests to dry deposition. The program calls for eventual deployment of up to 75 sites in the United States and close coordination with dry deposition monitoring activities in Canada. In addition, the Electric Power Research Institute (EPRI) is deploying a network which will complement the coverage provided by NAPAP and Canadian stations.

Because there is no simple direct method currently available for measuring dry deposition, the NAPAP is in the process of evaluating ongoing and proposed research programs designed to develop such a method. Three core research sites have been established for comparing methods and developing Bench-mark values for computing dry deposition fluxes. This method would be used to either validate or replace the current indirect methods of measurement.

Rates of Aquatic Change

Recommendation:

Process-level data`from different watershed types would be of help for determining current and potential future effects of acid deposition on surface waters. Models for predicting watershed response to acid deposition should be developed and tested empirically. In addition, an adequate acid deposition data base on watershed characteristics should be developed to exercise the models for selected North American sensitive areas.

The National Surface Water Survey has described the chemistry of lakes and streams in potentially sensitive areas of the United States. These surveys provide a high quality baseline against which to measure potential change.

The Direct/Delayed Response Project (using the 3 best available models) predict the rates of change of surface water chemistry. The application of these models has required the development of a data base on relevant watershed characteristics. The areas currently under examination are the northeastern U.S. and the southern Blue Ridge Province. The Watershed Manipulation Project verifies modeling data through controlled watershed acidification studies. The project is in the early stages for Maine and an additional site is expected to be chosen shortly in either the mid-Atlantic or southeastern regions of the U.S.

Watershed research and stream monitoring conducted by the US Geological Survey, the National Park Service, and the U.S. Forest Service not only provides long-term stream or lake records but also contributes to an understanding of basic processes which determine how aquatic systems respond to acidic deposition.

Aquatic Biology

Recommendation:

> The environmental damage of surface water acidification should be understood in terms of biological changes. This would help to quantify the relationship between changes in surface water chemistry and changes in aquatic biota more clearly. Special attention should be focused on both rates and types of biological change.

Modest laboratory studies have provided information on how individual species react to different aquatic environments. However, research priorities recognize that improved understanding of aquatic chemistry changes is essential if we are to develop any ability to predict biological changes. To help translate the laboratory findings to the field environment, NAPAP researchers are artifically acidifying an isolated half of a Wisconsin lake while using the other half as a control. The principal goal of this effort is to understand the biological changes which take place and how they relate to the chemistry and other field factors.

Major projects on fish sensitivity are being conducted by EPRI, and by the Central Electricity Generating Board in the United Kingdom. NAPAP researchers are tracking these and other relevant developments.

Forest Effects

Recommendation:

> Research should be accelerated to investigate the potential link between forest and tree decline and acid rain as a causal or contributing factor.

Changes in the budget reflect a dramatic acceleration of forestry research. In 1984, the NAPAP budget for forestry research was less than $1 million. The budget was increased to over $10 million in 1985, to over $18 million in 1986, and is at over $16 million in 1987.

NAPAP has in place a major research program to examine stresses on trees to separate out the effects of acid deposition from the effects of natural or other manmade factors. The scientific community has hypothesized several mechanisms by which acid deposition alone, in combination with its gaseous precursors and/or in combination with oxidants might be causing forest effects. To date, insufficient data and information exist to test hypotheses or to determine if there is a causal link between acid deposition and observed forest changes, but much more information will be available within the next 2 or 3 years.

The current research program is addressing four forest types—spruce-fir forests, southern conifer forests, eastern hardwood forests, and western conifer forests. The program is aimed at identifying any visible damage and growth reduction on certain species in specific geographical areas and then conducting controlled field and laboratory studies to test various hypotheses.

The current research program expects as one of its primary accomplishments to establish whether acid deposition does or does not play a role in observed forest effects. Over the longer term, the program expects to establish the relative contributions of acid deposition, air pollution, and natural stresses in various combinations to effects on forests.

Materials Damage

Recommendation:

> The effects of acid rain on materials should receive increased attention so that the quantifications of the extent of current damage, the resources at risk, and the prognosis for future damage can be improved.

To resolve the considerable uncertainty about the estimates of damage to materials, NAPAP has a multimillion dollar research program which, after considerable review and consideration, is being restructed to focus for the short term solely on the development of damage functions which will provide a basis for determining the incremental effects of ambient acidic deposition on metals, two types of carbonate building stones (limestone and marble), and a variety of paint systems. This program is built on carefully controlled laboratory studies, field exposure site studies (conducted in a joint program with Canada and the ECE) to verify the understandings established in the laboratory, and an examination of materials in place in a variety of structural and cultural settings.

Role of Heavy Metals

Recommendation:

> The mobilization, transport, and flux of heavy metals in acidified surface waters should be investigated to determine their environmental toxicity. Special emphasis should be placed on potential effects on human health and on possible mitigation strategies. The role of these metals in aquatic and forest damages also needs more attention.

NAPAP has conducted several modest studies of heavy metals in emissions, deposition, drinking water, fish, lake sediments, and tree rings. Future studies may examine actual regional deposition fluxes over representative areas, potential relation of the mercury content of surface waters and fishes to acidic deposition and mobilization of heavy metals in water supply systems. Where a linkage exists at high acidity or is possible at ambient levels, (e.g. for aluminum, a material which is mobilized by acidification processes in aquatic ecosystems), research programs are in place.

1.2.2 NAPAP Research Programs

The NAPAP research program is conducted by six federal agencies with a total expenditure of over $80 million annually. The research effort is conducted in seven task groups: Emissions and Controls, Atmospheric Chemistry, Atmospheric Transport and Modeling, Deposition and Air Quality Monitoring, Terrestrial Effects, Aquatic Effects, and Materials Effects. The research of these Task Groups is described in general in the following discussion. It will be described on a project-by-project basis in the soon-to-be released 1987 Operating Research Plan.

In addition to the work conducted in the Task Groups, the ODR develops syntheses of information, termed assessments, which interpret the research conducted and present them in a form useful for decision makers. The first such assessment will be completed by June 1987, and will be followed by two more assessments before the close of the program in 1990.

Task Group I - Emissions and Controls

1990 OBJECTIVES:

1. Assess emissions of SO_2, NO_x, and VOC

   Historical seasonal/state 1900-1990
   Monthly by State 1975-1989
   Detailed by month, typical hourly profiles, all relevant chemical species, and 20 km grid for 1980 and 1985
   Natural Sources by Region

2. Develop a comprehensive model for predicting emissions and control costs of SO_2, NO_x, and VOC under alternative assumptions of production, technology, and economics.

3. Compile a current summary of existing and potential control technologies and costs.

PROGRAMS:

Emissions Trends

Historical trends of SO_2, NO_x, and VOC at 5-year intervals from 1900-1980 on a regional basis will be completed in FY 1987. They will be calibrated by the 1980 detailed emissions inventory. In 1989, the calibration will be refined by the 1985 detailed inventory. This data is used for estimation of historical deposition and effects.

The operational trend emissions inventory has been produced annually since 1975 at the month/state level of detail. This will continue. Estimates of the uncertainties in the month/state inventories will be made and procedures will be developed to reduce the uncertainties.

Detailed information on fossil fueled utility boilers will be assembled each year to support the monthly/state inventories, the 1985 detailed inventory, the utility emission prediction module (AUSM), and future control/cost studies.

1985 Detailed Emissions Inventory

A comprehensive emissions inventory based on detailed 20 by 20 km grid cells, 20-25 chemical species, and representative hour for each week day and season will be prepared using the National Emissions Data System as the primary source and modified by other information sources. The compilation will be subject to rigorous QA/QC procedures.

Estimates of uncertainties will accompany final derived quantities. This Detailed Inventory will provide the basis for assessment and regulatory analysis, basic input to application of RADM and other atmospheric models, validation tests of the RADM, and calibration of the monthly/state operational trend inventory. It will be completed in FY 88.

Integrated Emissions Prediction Model

This comprehensive model is composed of sector models (modules) focused on emissions from major source categories: utility, residential/commercial, transportation, and industrial. The model can be exercised over a wide variety of values for all important parameters, e.g., economic activity, fuel use, control technology, electric energy use, retirement life. The Integrated Model will be initially complete in 1987. It will be peer reviewed, modified, tested, and fully documented during FY 87 and FY 88 so it can be used in FY 89 and FY 90 to examine relevant scenarios of control.

Control Technology Studies

Future efforts will include updating current and advanced technologies for control of emissions of SO_2, NO_x, and VOC. Emphasis will be placed on capital and operation costs vs. percent emission reduction for both new sources and retrofit situations. Technology developments in the U.S. and abroad will be included in the update.

Task Group II - Atmospheric Chemistry

1990 OBJECTIVES:

1. Estimate with adequate accuracy the natural background flux of SO_2, NO_x, NH_3, VOC, and alkaline dust in to air and the corresponding pH of precipitation on a regional basis by season.

2. Produce an adequate understanding of chemical processes in clear air that produce acids and related oxidants from the precursors SO_2, NO_x, and VOC.

3. Produce an adequate understanding of the chemical reactions in the aqueous phase of clouds, fog, and precipitation and the scavenging of acidic species in vapor or particulates from the atmosphere.

4. Establish the concentration of acidic species and oxidants in mountain clouds and ground level fogs.

5. Determine the relevant processes that produce dry deposition. Develop a quantitative monitoring system from dry deposition. Estimate the relative contribution of dry to wet deposition of S and N by distance from source and by season.

6. Develop and validate atmospheric chemistry modules that will link efficiently into comprehensive mesoscale of regional acid deposition models being developed by Task III.

PROGRAMS:

Natural Emissions

This program will assess and improve regional natural emission inventories for sulfur, nitrogen, and hydrocarbon compounds, and for ammonia and alkaline dust. Natural sources (e.g., vegetation, bacteria, lightning) are widely distributed, weak, and highly variable. Measurement of source strengths as a function of chemical species has often required development of improved techniques.

These data are required for the assessment of the natural background and its variation which sets the reasonable lower target for control of manmade emissions. In certain parts of the country, natural fluxes of pollutants may be a significant fraction of the total and, therefore, are essential to provide complete model predictions for source/receptor relationships.

Gas-Phase Chemistry

Chemical reactions in clear air may provide acids directly. The major reactive photochemical oxidants (free radicals, ozone, and hydrogen peroxide) combine with sulfur dioxide, nitrogen dioxide, and organic compounds to produce acids. The chemical knowledge of these reactions is fairly well known, but important gaps exist for hydrogen peroxide and nitric acid formation and nitrogen-oxide products. This program will establish the mechanisms, reactive intermediates, rates, and final products for the gas-phase chemistry responsible for acidification.

It will also develop and improve experimental and theoretical techniques for determining local and regional average air concentrations of intermediates and products of acidification. This information is necessary as a basis for improving atmospheric models developed under Task Group IV.

To accomplish the above objective, laboratory-controlled studies must be made as well as intensive field exercises. The concentrations of intermediates (e.g., hydrogen peroxide, formaldehyde) and products (e.g., nitric acid vapor) are generally below the sensitivities of standard instrumentation so that technique development is an integral part of the program.

Aqueous Chemistry/Scavenging

This program is directed toward understanding the chemical reaction in clouds and fogs that produce acids and the scavenging of acidic aerosols and vapor from falling rain. This requires laboratory studies to measure the rates of reaction and the equilibrium conditions for the wet removal process.

It also requires field investigations to characterize precipitation scavenging mechanisms in various storm types. The current theoretical and laboratory knowledge is insufficient to describe the wet scavenging process without guidance from field observations.

These data and theory are being used to produce models for the aqueous chemistry and scavenging which can be used to predict wet deposition as a function of the chemical composition of the clear air and the cloud forming and precipitation processes. These models are being designed to be a part of the comprehensive mesoscale (MesoSTEM) and regional (RADM) wet deposition models. The results of this work will, in part, define the degree of linearity between source strength and wet acidic deposition in key receptor areas. It is therefore basic to the design of source control strategies for targeted reductions in deposition.

Mountain Cloud and Fog Chemistry

Measurements at selected sites above average cloud base on mountains, or at low elevations where fog is common, will characterize the chemical composition of both water droplets and associated clear air in clouds and ambient air in the absence of clouds or fogs. The emphasis is on acids and oxidants (e.g., O_3 and H_2O_2).

Further, attempts will be made to estimate dry, cloud, and wet chemical deposition to selected mountain forests canopies as a function of elevation, average wind speed and direction, and season.

Dry Deposition

This program comprises the development of methods for flux estimation, the advancement of necessary chemical sensor improvement, and the operation of Monitoring Research Sites.

Dry deposition including both deposition of aerosols and reaction of gases such as SO_2 and HNO_3 with surfaces is a process that contributes substantially to acidic deposition. The process is a combination of atmospheric turbulence at ground level, variable surface features, and physiological activity. Monitoring of dry deposition is required for investigating changes in surface water chemistry, biological, and material extrapolated damage, evaluation of atmospheric models, and documenting long-term trends of total acid deposition. The measurement of dry deposition rates is difficult; presently, there is no standard method, although there are several research methods under development.

Dry deposition monitoring results for point monitoring stations must be extrapolated to obtain estimates of deposition in large areas. To gain credibility in those estimates, the errors in the techniques of monitoring and extrolation must be quantified.

Task Group III - Atmospheric Modeling and Transport

1990 OBJECTIVES:

1. Provide efficient source-receptor models for both regional and mesoscale that are fully documented.

2. Complete validation of these models to determine their level of accuracy.

3. Demonstrate the application of these validated models to:

   Predict deposition and air quality at sensitive areas from given emission sources.
   Establish relative importance of local vs. distant sources.
   Examine non-linearities in Source/Receptor relationships.

PROGRAMS:

Development of Regional and Mesoscale Models

The RADM, its associated input modules of atmospheric chemistry, atmospheric transport, dry deposition and precipitation scavenging, and the mesoscale model, will be essentially complete by FY 88 except for some fine tuning of the simplified (engineering) version of RADM.

Model Application

The Engineering and Mesoscale models will be exercised for preliminary assessment analyses and to evaluate the performance of the Engineering model in comparison to the more complex RADM model.

Model Evaluation

The major effort in 1987 and beyond is to conduct intensive field studies in an attempt to validate, and subsequently revise and improve the RADM. In two intensive periods of 1-2 months each separated by about a year, the model prediction will be compared in time and space with actual air quality and deposition. Ground level sampling will be done with a dense network of wet deposition and air quality measurements. To collect data on the chemical composition, and physical condition at altitude, aircraft, and radiosonde techniques will be employed. The NAPAP network will be supplemented by stations operated by EPRI and Environment Canada. A major effort will be made to enable the RADM to predict seasonal average deposition and air quality. The application to source/receptor scenarios will follow the validation.

Special Studies

The Task Group's special projects include estimation of the gross flux of pollutants into the RADM domain from the mid-Continent and off the Atlantic Coastline to the east. Some effort on using trajectory analysis for source/receptor relationships will be continued.

Task Group IV - Amospheric Deposition and Air Quality Monitoring

1990 OBJECTIVES:

1. Determine the spatial and temporal variations in the composition of atmospheric deposition within the United States by means of nationwide monitoring networks.

2. Estimate the background composition of atmospheric deposition worldwide through operation of deposition monitoring and research sites at remote locations.

3. Provide air-quality measurements needed for evaluation of atmospheric models and for assessment of effects due to atmospheric deposition.

4. Have developed methods for reliable measurement of dry deposition.

5. Have in place an integrated storage and retrieval system for atmospheric deposition and air-quality data for the United States.

PROGRAMS:

Wet Deposition Monitoring

About 150 wet deposition monitoring stations (NTN/NADP) are now operational across the coterminous United States supplemented by 10 remote sites around the globe. Numerous agencies support subsets of this network. The stations are operated on a weekly basis according to a consistent, rigorous protocol. The chemical analyses are done at a central laboratory. All activities from sampler function to final data compilation are subject to careful quality assurance and quality control procedures.

The data is systematically compiled and summarized on a yearly basis at PNL and is available to NAPAP users. Supplementary data from useful, but less comprehensive stations or networks, will also be available from this data bank.

The QA/QC'd data will be summarized in tabular and graphic form on an annual basis by PNL. In addition, this data bank will include rain and cloud composition measurements from the Mountain Cloud Network. These data will be analyzed and interpreted by many groups, (e.g. GS, EPA, NADP) each for their own objectives, as well as the NAPAP assessments. For NAPAP objectives, EPA and PNL will be concerned with isopleth methodology, GS with trend analysis, and the NAPAP assessment with integration of deposition with effects. Where needed in intensive studies for model validation, parallel samplers, that operate on different schedules, will be operated at selected stations.

Dry Deposition Monitoring

Dry deposition is relatively more important than wet deposition closer to emission sources. At regional distances (hundreds of kilometers), it may equal the wet deposition. The technology for quantitative measurement of dry deposition is still under development (see Task Group II), but enough is known that it is imperative that a comprehensive rural air quality network be established which will provide the data base for the estimation of dry deposition. Such a network will also give quantitative measures of the concentration of gaseous pollutants required to assess effects. As the calibration factors are refined by the work of Task Group II the uncertainties in the regional dry deposition will be successively reduced. A total of about 100 of these "dry deposition" are contemplated to be established in 1987 and 1988 by NAPAP (45-65) and EPRI (30-40) and then operated for the remainder of

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the NAPAP. Funds in this program are primarily for the establishment and operation of the stations, the necessary QA/QC, and the data system. As with wet deposition, annual summaries will be produced. In addition, the NAPAP air quality data base at PNL will include measurements from other relevant stations.

Deposition Monitoring Research

This program supports the Wet Deposition Research Stations at Whiteface Mountain, New York, Penn State University, and the MAP3S sites. It includes funds for laboratory support as well as field operations. The effort is focused on improvement of deposition collection efficiency, accuracy, and protocols for the routine monitoring networks.

The scope covers deposition technology for rain, fog, gases, particles, and snow.

A related effort involves coordination and intercalibration with the Canadian network and major acid deposition laboratories in Europe.

Task Group V - Terrestrial Effects

1990 OBJECTIVES:

1. Determine the effect on productivity of representative agricultural crops from exposure, near-ambient levels, to acidic deposition and associated oxidants.

2. Determine the effect on productivity and health of major tree species from exposure of to foliage, to near-ambient levels of acidic deposition and associated oxidants.

3. Estimate the long-term effect on productivity and forest health from acidic deposition on a wide variety of forest soils at near-ambient levels.

4. Identify the major factors causing visible damage to forests above cloud base in the high mountains or the eastern United States.

PROGRAMS:

There are several major programs under the Terrestrial Effects Task Force. The program on the effects on agricultural crops is supported by the U.S. Department of Agriculture that the Cooperative State Research Service (CSRS) and the Agricultural Research Service (ARS). The forestry program is supported jointly by the EPA and the U.S. Forest Service in an organizational arrangement called the Federal Management Group. The research is carried out in Cooperatives, focused on specific forest types, which enlists forest scientists from many universities in the region as well as government laboratories. The efforts in forestry are closely coupled with research in several other Task Groups, i.e.; Aquatics, T.G. VI (forest soils modify the composition of chemical deposition before it enters streams and lakes), Mountain Cloud Studies, T.G. II (acids and oxidants in clouds impact the foliage of the forest canopies as well as the thin high-altitude soils) and Dry Deposition, T.G. II (deposition depends in part on the filtration efficiency of the forest canopy).

Agricultural Crops

Past research has demonstrated that agricultural plants are measurably retarded in their productivity by ozone. In constrast, no important effects of acid rain on crops have been observed under near-optimum growing conditions, at constant levels of exposure, in controlled experiments. Nevertheless, there remain significant gaps in our knowledge that must be filled in before the conclusion of NAPAP. These gaps, which were identified in a NAPAP workshop in March 1986, define future research.

1. Examine the importance of different exposure dynamics (e.g., concentration peaks, respite time, stage in growth cycle) in affecting crop productivity.

2. Determine by mechanistic studies whether certain environmental factors, e.g., ozone concentration and moisture stress have an interactive effect with acidic deposition in affecting crop yield.

3. A few crops, most importantly the soybean cultivar 'AMSOY' have shown ambiguously positive results on impact from acidic precipitation in the ambient range. Highly precise dose/response studies of acid precipitation over the range of pH encountered in the agricultural regions where 'AMSOY' is grown are required to thoroughly characterize the response.

4. Determine effects of acidic precipitation on unmanaged grasslands and on locally important crops.

Southern Pine Forests

The most important commercial forests in the U. S. are the pine plantation and mixed pine hardwood natural forests of the coastal plain and piedmont from Virginia to Texas. Although no significant visible damage or mortality has been observed beyond what can be ascribed to natural causes, there are observations suggesting a decline in productivity in certain areas. The research program will determine whether current levels of acid deposition and associated oxidant concentrations have a negative impact on growth in these forests. The major efforts in the near-term can be summarized as follows:

1. Dose/response studies under controlled conditions of simulated acid precipitation and ozone (and to a limited extent SO_2 and NO_x) over a range of concentration from background to high ambient on seedlings of a wide variety of pine genotypes. These studies will include interactive effects of the pollutants with each other and with environmental stresses such as drought. They will examine dose/response effects as a function of dose rate and of the time in the growth cycle. Multiyear tests will be conducted to determine the relation of response to the age of the tree.

2. Nutrient cycling and potential soil depletion studies will be carried out to understand the importance of incremental leaching of foliage by

wet acidic deposition and the impact of acid deposition on soils with relatively low neutralizing capacity.

3. Examination of the potential impact of nitrogen deposition and the possible release in the soils of heavy metals and aluminum on the microbiological systems that support tree growth.

4. Studies to understand the physiological mechanisms of observed effects on tree growth from wet and dry acidic deposition and associated oxidants.

5. Establish several intensive forest research sites where the potential biological impact of acidic deposition and associated oxidants may be carefully monitored on young trees in partially controlled conditions, and on associated mature forests on different soil types. Comprehensive deposition and air quality measurements will be made at these sites including throughfall and stemflow.

Spruce-Fir Forests

Aside from the seriously damaged conifer forest in the San Bernadino national forest of the Los Angeles Basin, the only significant visible decline and mortality of a U.S. forest possibly due to regional air pollution (acids and/or oxidants), is found in the above cloud base spruce-fir forests of the high mountains of the Blue Ridge, (VA, NC-TN) Adirondacks (NY), Green Mtns. (VT), and White Mtns. (NH). The research in this program is designed to understand the major cause or causes of the mortality observed in the above cloud base forests as well as to examine the reported growth reduction in the northern spruce-fir forests generally.

The major efforts in this program are:

1. Dose/response studies of acidic precipitation, acidic mists, gases (O_3, SO_2, NO_x) and H_2O_2 in cloud droplets in the range of ambient levels on the foliage of spruce and fir seedlings of various ages. These studies will include interactive effects of the various pollutants as well as the interaction with frost and drought conditions. The relative efficiency of ozone impact with and without saturated mist (cloud simulation) at various times of the day will also be examined.

2. The effect of acidic deposition (rain and mist) on the leaching of essential nutrients from the foliage and their possible significant depletion in the high altitude soils will be examined.

3. The effect of excess nitrogen and ozone on the frost hardiness of the trees will be simulated under controlled conditions as well as examined in the field where significant gradients are found.

4. The interaction of spruce-fir pathogens, insects, ectomycorrhizae with other natural stresses and pollutants will be studied.

5. The above cloud environment (both in-cloud and clear air chemistry) and its diurnal, meterological, and seasonal variation is needed to design the most realistic conditions for the dose/response studies and to

translate their results to the real forest. This data will be supplied by the Mountain Cloud Program in Task Group II.

Western Forests

These forests may be roughly divided into two major categories: (1) the ponderosa pine-fir forests of the Rocky Mountains, the east side of the Cascades and the Sierras and the southern California mountains; (2) the Douglas Fir forests of western Oregon, Washington, and northern California. Acidic precipitation is probably less of a problem on these forests as the average annual pH of rain is much higher than in the eastern U.S. (i.e. > 5.0) with the exception of the Los Angeles basin. On the other hand, significant levels of ozone have been observed on the west slopes of the Cascades and Sierras. Unique to California are the high nitrate, high acid fogs in the Los Angeles basin, and the southern San Joaquin Valley which may have deleterious effects on trees.

The Western Forest program is analogous to that for the Southern Pine and Spruce Fir Cooperatives but on a more modest scale.

1. Dose/Response studies will be conducted to determine the SO_2, NO_x, O_3, and acid fog impacts on the growth of prime key conifer species of the west. The interaction of these pollutants with each other and with humidity and soil moisture will be examined.

2. The ambient levels of the pollutants in these forests will be obtained by extensions of the nationwide deposition and air quality monitoring covered by Task Group IV and the Mountain Cloud Program (T.G. II).

3. The roles of foliar cation leaching, foliar nitrate uptake, and nutrient availability to the roots in the responses of Douglas Fir and Engelmann spruce to acid precipitation will be determined.

4. The relationship of the spatial pattern of insect/pathogen occurrences in western conifer forests will be compared with the patterns of acidic deposition and ozone concentrations.

5. Attempts will be made to quantify the relationship of the dose/response effects on young trees to mature trees using a branch enclosure technique on trees in their natural environment.

6. Field surveys will be made across strong pollutant gradients to investigate possible alterations of western forest ecosystems.

Eastern Hardwood Forests

A large part of the forested areas east of the Mississippi River is covered by eastern hardwoods. Widespread decline with visible mortality has not been observed on a regional scale aside from disease and insect epidemics. Possible exception of sugar maple and white pine (scattered among the eastern hardwoods) which in the latter case has been ascribed to its greater sensitivity to ozone. Nevertheless, general reduction in growth has been reported in some areas that are not readily explained by natural causes. The oxidant levels in the northeastern part of the hardwood regions are comparable to that in the southeast or central east, but the acidic precipitation reaches a maximum in eastern Ohio, West Virginia, and western Pennsylvania. A significant downward gradient exists in the pH of rain on the hardwood forests from the Mississippi Valley to Ohio which then increases again toward Maine. The Eastern Hardwood Program is designed to investigate the effect of acidic precipitation and ozone on the major species in the Eastern Hardwood forests by controlled dose/response work and by field studies across the gradients as follows:

1. Dose/response studies of the effect of acidic precipitation and ozone alone and in combination, at ambient levels, with and without moisture stresses, on the productivity and health of seedlings of several ages representing the major (10-12) species comprising the Eastern Hardwood Forest region.

2. Nutrient cycling studies to determine the role of foliar leaching and soil impact from acidic precipitation will include the use of sulfur and nitrogen tracer technology.

3. A careful reanalysis of the data underlying the historical declines in these forests and the relative role of various natural stresses.

4. Field study of selected plots across the deposition gradients to search for systematic correlations that cannot be accounted for by natural causes.

Integration and Management

This program will direct the QA/AC for the entire forestry effort, will manage the data base, will assist in interpreting the results planning future research and will conduct studies relative to assessment as requested by the Office of the Director of Research.

Task Group VI - Aquatic Effects

1990 OBJECTIVES:

1. Quantify the extent, location and characteristics of sensitive and acidic lakes and streams in the United States.

2. Quantify the factors that control sensitivity of surface waters to acidic deposition.

3. Adequately predict the rate of change of the chemical composition of streams and lakes as a function of acid deposition.

4. Determine the relationship between surface water acidification and stress on biological populations.

5. Determine the potential effects of freshwater acidification on human health.

6. Produce an ecological evaluation of techniques for restoring or protecting acidic lakes and streams.

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PROGRAMS:

Chemical Status of Sensitive Surface Waters

~~This program~~ This program has two major components: (1) the National Surface Water Survey, and (2) the Episodic Response Study. In 1985 and 1986, over twenty five hundred lakes and several hundred stream reaches were sampled. The lakes were sampled in the fall, the streams during nonstorm spring runoff. These samples provide a statistically valid estimate of the number, area, and percentage of lakes and streams in potentially sensitive areas (Phase I) that show various levels of acidity. A subset of these lakes, chosen to be representative, will be sampled in three dimensions over the four seasons in the next few years to understand the annual variability (Phase II). This study will be complemented by the Episodic Response Project which will examine the magnitude and duration of low pH events that accompany snowmelt or storm events. The chemical data gained from these more intensive studies will be the basis for population estimates for all lakes and streams in each region. (OBJECTIVE 1)

Watershed Processes

This program examines the factors affecting surface water chemistry. These include the chemical composition of annual or seasonal total deposition, soil surveys, soil reaction mechanisms, biogeochemical modification of sulfate, and nitrate ions and hydrology at a representative set of watersheds. The appropriateness of these systems is known as a result of Phase I and II of the surface water survey. Some of these watersheds have historical records of the factors of interest. For others baseline data will be collected prior to manipulation. (OBJECTIVE 2)

Model Development

Based on an understanding of the mechanisms derived from the Watershed Studies, models will be tested, and refined that will describe the relationship between present wet and dry total deposition and present surface water chemistry. They will also predict changes that will occur in the surface water chemistry over time (years to decades) as the deposition increases, decreases, or remains constant. (OBJECTIVES 2 and 3)

The Future of Surface Water Chemistry

Once the present acid status of lake and stream is determined, the next important question is how the acid and associated sulfate and nitrate concentrations will change in the future with lower, higher, or constant deposition. This critical issue is addressed by four programs: (1) Study of chemical behavior of acid deposition selected watersheds, (2) Development of a comprehensive model which adequately describes the relation of past deposition to present surface water composition, (3) Manipulation of Watersheds, and (4) Long-Term Monitoring. (OBJECTIVE 3)

Ecosystem Manipulation

This program will test, the watershed models by manipulating the composition and amount of acid deposition and tracking the impact on surface water chemistry. The resultant information will permit enhancement of the models.

Other projects under this program will (1) address lake liming to mitigate acidification of surface waters, and (2) track the sequence of ecological events which occur as lakes acidify. (OBJECTIVES 2, 3 and 6)

Long-Term Monitoring

The ultimate validation of the model will be obtained by long-term monitoring of selected watershed systems to compare actual surface water chemistry over time. This program will also provide an updated baseline to track the effect of future deposition. (OBJECTIVE 3)

Biology of Sensitive Waters

The effects on biological resources (particularly fish) as a result of acidic deposition are being studied to define threshold concentrations of chemicals in surface waters that are detrimental to primary consumers. Effects from both chronic and episodic exposures will be examined. The primary focus will be on key recreational and commercial fish species with secondary emphasis on primary producers, zooplankton, benthic invertebrates, amphibians, and waterfowl.

In conjunction with Phase II of the National Lake Survey, the presence or absence of key fish species in a subset of lakes in the northeast with a broad range of acid-neutralizing capacity will be determined.

Because of the complex geometry of stream networks and the presence of refuges into which fish can avoid the more extreme changes in chemical composition, the focus of biology in streams and lakes will be on the mortality of fishes held in cages exposed to episodes of different magnitude and duration at a relatively limited but regionally representative number of study sites. These results will be compared with impacts of chemical composition on the same species and age of fish in controlled tank experiments. This program started in FY 86 and will continue through the life of NAPAP.

To support the interpretation of empirical field data on fish populations as a function of lake or stream chemistry, studies will be conducted on the physiological effects from both acute and chronic exposures on survival condition, and recruitment. This will be centered in laboratory-controlled bioassays supplemented by field exposure experiments. (OBJECTIVE 4)

Human Health Effects

The objective of this program is to determine whether that portion of the population that drinks unprocessed or unregulated water, i.e., well water and cistern water, can experience significant, negative health effects from acidic deposition. This will be assessed by determining the composition of untreated drinking water in areas of high acid deposition and comparing this with present health standards.

A special subprogram will involve the analysis of tissues from fishes collected in representative lakes to search for elevated mercury concentrations. Where elevated levels exist, studies will be directed toward the possible link with acid deposition. Lakes in the Northeast, Florida, and the Mid-west will be sampled for each major species of game fish and forage fish. The analyses of total mercury and methyl mercury will be conducted by EPRI in a cooperative arrangement. (OBJECTIVE 5)

Task Group VII - Effects on Materials and Cultural Resources

1990 OBJECTIVES:

1. Quantify the effect of acidic deposition and associated oxidants incremental to natural background on materials degradation.
2. Estimate the quantity and geographic distribution of materials that are significantly impacted by incremental deposition.
3. Estimate the cost of the incremental impact on materials damage where measurable.
4. Evaluate the feasibility of substitution, protection, and other strategies to mitigate materials damage.

The Task Group's priority is to focus on goal 1, the development of damage functions. Progress towards meeting the other objectives is contingent upon satisfactory progress towards meeting this first objective.

PROGRAMS:

Field Test Sites

The field test sites will continue operation. Research at these five sites and a sixth cooperative site in Canada provides for detailed measurements of environmental exposure (including wet deposition and air concentration of relevant acids and associated compounds) and of the degradation of metals, carbonate stone, and paint systems. In addition to exposure under existing environmental conditions, the facilities at one intensive test site is being enhanced by the installation and operation of fumigation chambers and rain simulators which will allow for manipulation of sulfur dioxide concentration and rainfall acidity. Further, the orientation of materials at the field sites is being examined to determine how geometry (vertical, horizontal, north, south, etc.) affects degradation of materials.

These measurements provide a basis to translate conclusions about materials degradation based on highly controlled laboratory measurements to the real environment.

Metals

The cause and effect relationships of wet and dry deposition, galvanized steel, and other selected metals will be studied in controlled chambers. Effects from variation in concentrations of SO_2, acidity, wet and dry surfaces, sequence temperature, diurnal cycle, and methology will be quantified. Damage functions for acid, SO_2, and NO_x concentration in excess of natural background will be derived from these controlled laboratory experiments. The results will be compared observations from the field tests which approximate the total ambient environment. A study of the inventory, replacement patterns, and replacement costs of uncoated galvanized steel will be conducted. If the incremental costs from acidic deposition are significant, an assessment of the economic costs will be made.

Carbonate Stone

This program is an analog to that of metals: (1) controlled laboratory studies to obtain damage functions for simple cases, (2) field tests to compare predictions from the laboratory experiments with the real environment. including dose/response relationships from variable acid, SO_2, and NO_x concentrations, and (3) extrapolation to real buildings and monuments.

Paint

Research on paint will build on the base initiated in 87 to develop damage functions for at least two paint systems: paint on wood and paint on metals. In each instance, several types of both latex and oil based paints will be evaluated. The work will progress from the work on degradation mechanisms determined in the laboratory (initiated in FY 86) which will identify reliable early microscopic predictors of subsequent macroscopic paint failure. This approach will allow for the accelerated development of damage functions for paint systems.

Research on paint is essential for meeting Task Group objectives. Analysis within the National Program and clear direct and unambiguous comments by peer reviewers indicate that although prior work has not established the incremental effect of acidic deposition on paint systems, the large areas in the inventory could equate to significant costs.

Special Studies

Special studies will focus on the degradation of cultural and construction materials in actual use. This includes determination of the variation in microclimate around building surfaces, how building components interact, and how damage functions can be applied to complex of structures. These studies provide the final refinement to damage functions developed in the laboratory and modified by results from field tests.

A small project will provide for the intercomparison of field test data collected at U.S. and a large number of European exposure sites.

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PART 2. JOINT UNITED STATES-CANADA PROJECTS

Joint Projects between the U.S. and Canada in the area of acidic deposition have been in operation since 1982. The number has steadily increased until today there are nineteen projects distributed in areas of Forest Effects, Aquatic Effects, Atmospheric Transport, Deposition Monitoring, and Effects on Materials. Particular emphasis has been placed on intercalibration of sampling protocols and laboratory analysis so that results are consistent across North America. In the development and testing of regional transport models of atmospheric pollutants, close cooperation has been established. Mutual support and full exchange of data exists in areas of acidic deposition and air quality, monitoring, cloud chemistry at high elevation in the Appalachian chain, material samples at test sites, national emission inventories, cross continent tracer experiments, and surface water chemistry surveys.

Current cooperative projects are listed in Table 1. A report describing these projects is available from the Canadian or U.S. research coordination offices.

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TABLE 1

U.S.-CANADIAN COOPERATIVE ACID DEPOSITION RESEARCH PROJECTS

December 1986

Activity	Purpose	Participating Organizations U.S.	Participating Organizations Canadian
FOREST EFFECTS:			
North American Forestry Commission	Acid Deposition Study Group	Forest Service	Forestry Service
Peer review	Joint peer review of U.S. and selected Canadian terrestrial effects research	NAPAP	Forestry Service, Atmospheric Environment Service
Data exchange	Impact of acidic fog and clouds on forests	Forest Service, EPA, State Univ. of New York/Albany	Forestry Service, Atmospheric Environment Service, McGill Univ.
* Research planning	Assess cause of sugar maple decline (other hardwoods)	Forest Service	Forestry Service
AQUATIC EFFECTS:			
Monitoring program	Exchange of information on protocols and quality assurance activities	EPA	Environmental Conservation Service
Data exchange	Interpretation and evaluation of U.S. and Canadian surface water chemistry surveys	EPA	National Water Research Institute
Methods intercomparison	Exchange of samples of free aluminum in surface waters	Univ. of Maine	Ontario Ministry of the Environment

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* Denotes potential new cooperative project discussed at November 1986 RMCC/NAPAP meeting.

Activity	Purpose	Participating Organizations U.S.	 Canadian
ATMOSPHERIC PROJECTS:			
Joint research planning and design	Eulerian acid deposition and oxidants model development	EPA, National Ctr. for Atmospheric Research	Ontario Ministry of the Environment, Atmospheric Environment Service
Field study	Performance evaluation of acid deposition models	EPA	Ontario Ministry of the Environment, Atmospheric Environment Service
Model evaluation	Evaluation of International Sulfur Deposition Model	EPA	Atmospheric Environment Service
Workshop	Cross-Appalachian Tracer Experiment (CAPTEX) data analysis and model comparisons	Natl. Oceanic & Atmospheric Admin., Dept. of Energy	Atmospheric Environment Service, Ontario Ministry of the Environment
Cooperative field study	Determination of pollutant concentration, deposition and horizontal flux with distance over the North Atlantic (WATOX)	Univ. of Virginia, Natl. Oceanic & Atmospheric Admin., Bermuda Biological Sta.	Atmospheric Environment Service
Cooperative research	Air/Ocean Chemistry Experiment (AEROCE): to investigate biogeochemical cycles of trace species of the North Atlantic	Univ. of Rhode Island, Natl. Science Foundation	Atmospheric Environment Service
Data exchange	National emissions inventories	EPA, Dept. of Energy	Environment Canada
* Equipment transfer	Air quality/fog sampling at the Bay of Fundy and other eastern North American sites	Task Group II, NOAA	Environment Canada

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* Denotes potential new cooperative project discussed at November 1986 RMCC/NAPAP meeting.

Activity	Purpose	Participating Organizations	
		U.S.	Canadian
DEPOSITION MONITORING:			
Network intercomparison, co-location of samplers	Intercomparison of wet deposition networks i.e. U.S. National Trends Network (NTN) and Canadian Air and Precipitation Monitoring Network (CAPMoN)	Geological Survey, Natl. Atmospheric Deposition Prog., Ill. St. Water Survey	Atmospheric Environment Service, Environmental Conservation Service
* Network intercomparison, co-location of samplers	Intercomparison and co-location of sites for planned dry deposition monitoring networks	Geological Survey, Natl. Atmospheric Deposition Prog., Ill. St. Water Survey	Atmospheric Environment Service, Environmental Conservation Service
Laboratory intercomparison	Intercomparison of chemical methods used to analyze wet deposition samples	Geological Survey, Ill. St. Water Survey	Atmospheric Environment Service
Methods research	Development of standard methods to measure dry deposition	Natl. Oceanic & Atmospheric Admin., Geological Survey	Atmospheric Environment Service
Methods comparison, data exchange	Development of comparable sampling and analysis methods western monitoring	Wash. State Dept. of Ecology	B.C. Ministry of the Environment
Common data base	Unified acid deposition data base for eastern North America	EPA, Geological Survey, Natl. Atmospheric Deposition Prog., Pacific NW Natl. Lab.	Ontario Ministry of the Environment, Atmospheric Environment Service

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* Denotes potential new cooperative project discussed at November 1986 RMCC/NAPAP meeting.

Activity	Purpose	Participating Organizations U.S.	Canadian
EFFECTS ON MATERIALS:			
Co-location of samples at a variety of sites	Effects of acid deposition on the corrosion of structural materials	Bureau of Mines, EPA, Natl. Park Service	Atmospheric Environment Service
OTHER:			
* Joint Peer Reviews	Canadian participation in terrestrial and aquatic research peer reviews	NAPAP	RMCC

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* Denotes potential new cooperative project discussed at November 1986 RMCC/NAPAP meeting.

February 25, 1987

PART 3. NEW FINDINGS

Research is rapidly improving our understanding of the sources, transport, formation, deposition and effects of acidic precipitation. This report makes no attempt to review all of the new information but focuses on findings more relevant to resolving the bilateral problem in North America. Many of the findings have been taken from the Canadian Assessment of the State of Knowledge on Acid Rain, published in November 1986. Significant findings from the U.S. program have been largely obtained from the specific research components of the NAPAP program.

In order to help in limiting the material, four guidelines for selecting new findings were agreed upon and are listed below:

INTRODUCTION

1. The subjects to be covered in each section are findings which have become available since or not described in the Lewis-Davis report.
2. A new finding must be supported by a publicly available report which has been reviewed and released by a federal, state, provincial or other research agency, or which is at least in press in the peer reviewed literature and which is available for examination.
3. The report can be accepted by both the RMCC and NAPAP.
4. The geographic scope of the report will be the U.S. and Canada. However, reports of progress on processes from outside of this region are eligible for inclusion. Thus, reports of dose-response experiments or watershed manipulations from Europe could be included where relevant.

In order for any research program to produce reliable results it is essential to have good quality assurance of the analytical data. Quality assurance programs are carried out within both Canada and the United States and jointly between our two countries.

A Canadian LRTAP quality assurance program has been implemented and an intercomparison program supporting 65 Canadian laboratories (federal, provincial, university and commercial) and 10 American laboratories has been carried out. The program covers laboratories representing over 17 precipitation networks and five major watershed study areas. Parameters studied include major ions, nutrients, physical properties and trace metals in soft surface waters and precipitation samples. These results show that, in general, laboratories are reporting reliable data and those laboratories showing difficulties in earlier studies have, in time, shown a trend towards improvement.

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The ongoing quality assurance programs for monitoring wet deposition in the United States on a weekly basis involves a number of elements including the use of blind samples for laboratory analysis, reference samples for field measurements and field site inspections. There is an inter-laboratory comparison program involving the NADP/NTN Central analytical laboratory at Champaign, Illinois; the U.S. Geological Survey Central Laboratory at Denver, Colorado; the analytical laboratory of the Inland Waters Directorate, Environment Canada, at Burlington, Ontario (CAPMoN), and the analytical laboratory for precipitation chemistry of Environmental Monitoring Services, Inc. (UAPSP), at Newbury Park, California.

In addition to the laboratory programs, there is a paired-station program in Canada and the United States for comparing the results of daily operation of CAPMoN stations with weekly operation of NADP/NTN stations.

Results of these programs have indicated good adherence to the siting and operational protocols of NADP/NTN, analytical precision and bias within expected and acceptable levels, field measurements of acceptable quality, and good comparability between laboratories supporting the major precipitation monitoring networks in North America.

3.1 EMISSIONS TRENDS ESTIMATES

3.1.1 United States

Estimates of the emissions of SO_2 and NO_x by state and by month are compiled annually by the Argonne National Laboratory for the NAPAP using proven and consistent procedures based on fuel use and emissions factors.

1. Border and Selected Second Tier States

The most important states with regard to transboundary flux are the border states of Minnesota, Wisconsin, Illinois, Indiana, Michigan, Ohio, Pennsylvania, New York, Vermont, New Hampshire and Maine. Second tier states, Missouri, Kentucky and West Virginia are also significant due to their geographic location and relatively large emissions.
(Shannon and Lesht, 1986).

Table 2 compares the emissions of SO_2 for 1980 with those for 1984 and 1985 for the Border States and the three Second Tier States. The utility data for 1985 is complete. To obtain the 1985 emissions total it was assumed that the ratio of utility to total emissions remained the same as in 1980 and 1984. It is seen that since 1980 there has been about a 10% reduction in SO_2 emissions despite fairly uniform coal consumption. For the Border States this amounts to a reduction of about one million tons of SO_2. The three Second Tier States which contribute proportionately less to transboundary flux had a reduction 1980-85 of about 400,000 tons of SO_2.

2. National and Northeast Quadrant

Table 3 shows the trends in both coal consumption and SO_2 emissions for coalfired utility plants for the entire continental U.S. and the Northeast Quadrant. Emissions continue to decline despite increased coal consumption in the Northeast Quadrant due to increasing controls and substitution of lower sulfur coal. The U.S., as a whole, shows a leveling of SO_2 emissions in the past four years in spite of a significant increase in coal use. Since 1975 total U.S. SO_2 emissions have dropped by over a million tons while coal consumption has increased by about 70%.

SO_2 and NO_x Emissions from EPA Regions 1 through 5 (Figure 1) from 1975 through 1984 by source group are shown in Table 4. Total SO_2 emissions in the U.S. peaked in the early 1970's at about 30 million tons/yr. Thus by the 1982-84 period it has dropped by about 25%. In contrast the NO_x increased steadily from 1940 until about 1975, reached a broad maximum in the 1976-80 period and then declined slightly.

References:

Shannon, J.D. and Lesht, B.M. (1986). Modeled trends and climatological variability of the net transboundary flux of airborne sulfur between U.S. and Canada, Trans. 2nd International Specialty Conference on Meteorology of Acidic Deposition, Albany, NY, March 1986 (Air Pollution Control Association).

D. Knudson. Dec. 1986. Estimated monthly emissions of sulfur dioxide and oxides of nitrogen for the 48 contiguous States; 1975-1984, Argonne National Laboratory (ANL/EES-TN-318).

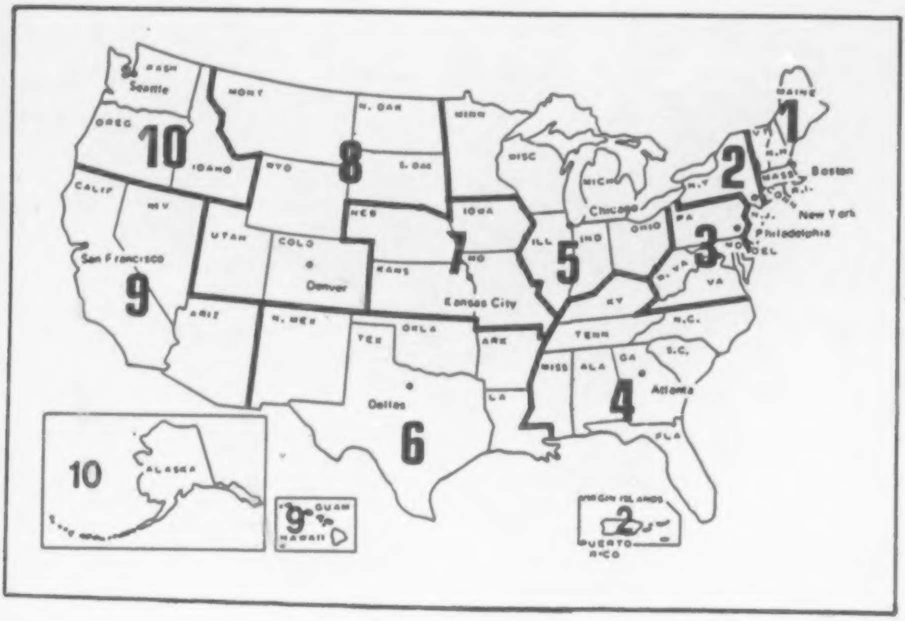
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Figure 1: EPA Federal Regions

TABLE 2

U.S. EMISSIONS OF SO_2 FROM BORDER AND SELECTED SECOND TIER STATES 1980, 1984, 1985

	1980		1984		1985	
	Utility	Total	Utility	Total	Utility	Total*
	(10⁶ metric tons/yr)					
Frontier States (MN, WI, IN, MI, OH, PA, NY, VT, NH, ME, IL)	7.5	9.8	7.0	9.2	6.7	8.8
% Decrease from 1980		—		6		10
Selected Second Tier States (KY, MO, W.VA)	2.9	3.3	2.5	2.9	2.5	2.9
% Decrease from 1980	—	—	—	12	—	12

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* To obtain the 1985 total it was assumed that the ratio of utility to total emissions remained the same as in 1980 and 1984.

US/CAN Submission Disk
DOC 5

TABLE 3

TRENDS IN SO_2 EMISSIONS AND COAL CONSUMPTION AT COAL-FIRED POWER PLANTS IN THE UNITED STATES AND ITS NORTHEAST QUADRANT

(10^6 metric tons/yr)

	Total U.S.			NE Quadrant		
	SO_2 Emissions	NO_x Emissions	Coal Consumption	SO_2 Emissions	NO_x Emissions	Coal Consumption
1975	15.4	3.6	368	12.0	2.6	248
1976	15.9	4.0	406	12.2	2.7	263
1977	16.0	4.1	433	11.9	2.8	271
1978	14.5	4.1	436	10.9	2.7	264
1979	14.8	4.4	478	11.1	2.8	279
1980	14.7	4.7	516	10.6	2.9	288
1981	14.5	4.9	541	10.2	2.9	289
1982	13.8	4.8	539	9.8	2.8	279
1983	14.0	5.1	567	9.8	2.9	291
1984	14.3	5.4	602	9.9	3.1	305
1985	14.2	NA	629	9.7	NA	307

Note: The NE and SE Quadrants are defined by an east-west line drawn along the southern borders of the states of VA, KY, and MO; and by a north-south line drawn along the western borders of the states of MN, IA, MO, AR, and LA.

TABLE 4

Emissions in U.S. Regions[1] 1 thru 5

(10^6 Metric Tons)

I. SO_2

	Year									
Source Group	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Utility	14.8	15.2	15.2	14.0	13.9	13.5	13.2	12.1	12.2	12.3
Ind. Fuel Comb.	2.0	2.0	2.1	2.1	2.0	1.8	1.8	1.7	1.6	1.7
Comm./Inst./Res.	0.6	0.6	0.6	0.6	0.5	0.5	0.4	0.5	0.4	0.4
Ind. Processes	1.4	1.4	1.4	1.4	1.5	1.3	1.3	1.1	1.1	1.2
Miscellaneous	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.5	0.5
TOTAL	19.3	19.8	19.8	18.6	18.5	17.7	17.3	16.0	15.8	16.1

II. NO_x

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Utility	3.6	3.8	3.8	3.8	3.9	4.0	4.0	3.7	3.8	4.0
Ind. Fuel Comb.	1.2	1.3	1.3	1.3	1.2	1.1	1.1	1.1	1.0	1.1
Comm./Inst./Res.	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4
Ind. Processes	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.3
Miscellaneous	0.9	1.0	1.0	1.1	1.1	1.0	1.0	0.9	0.9	0.9
Vehicles	4.3	4.5	4.6	4.6	4.4	4.3	4.2	4.2	4.1	4.1
TOTAL	10.8	11.3	11.6	11.6	11.4	11.2	11,0	10.6	10.5	10.8

NOTE:

1. See Fig. 1 for region identification.

Reference:

1. "Estimated Monthly Emissions of Sulfur Dioxide and Oxides of Nitrogen for the 48 Contiguous States, 1975-1989"; Agronne National Laboratory (ANL/EES-TN-318), D. Knudson; December 1986.

National Air Pollutant Emissions Estimates, EPA-450/4-85-014, Jan. 1986.

3.1.2 Canada

Sulfur dioxide emissions (Table 5) from nonferrous smelters decreased between 1970 and 1984 from 3.8 to 1.7 million tonnes (a 55% reduction) in response to a series of increasingly stringent emission regulations. The 1978 and 1982 emissions were particularly low due to lengthy shut-downs by two large smelters at Sudbury, caused by labor disputes and company needs to reduce annual production reflecting reduced demand.

Historical NO_x emissions from eastern Canada are given in Table 6 showing a gradual 20% increase from 1970 to 1978 followed by a level rate.

TABLE 5

Emissions of SO_2 - Eastern Canada[1]

Source Group	1970	1972	1974	1976	1978	1980	1982	1984
	Year							
	(10^6 Metric Tons)							
Industrial Processes								
Non-Ferrous Smelting[2]	3.8	3.2	2.9	2.6	1.8	2.0	1.3	1.7
Others	.4	.4	.4	.4	.4	.4	.3	.3
Fuel Combustion/Stationary Sources								
Power Generation by Utilities	.5	.5	.5	.5	.6	.7	.7	.7
Res/Commercial	.3	.4	.3	.2	.2	.1	.1	.1
Industrial	.6	.6	.6	.6	.6	.4	.3	.2
Transportation	.1	.1	.1	.1	.1	.1	.1	.1
TOTAL	5.7	5.2	4.8	4.4	3.7	3.7	2.8	3.1

NOTES:

1. Eastern Canada comprises the provinces east of the Saskatchewan/Manitoba border.

2. Includes copper-nickel, lead-zinc smelters only.

TABLE 6

Emissions of NO_x[1] - Eastern Canada[2]

Source Group	1970	1972	1974	1976	1978	1980	1982	1984
	(10⁶ Metric Tons)							
Fuel Combustion/Stationary Sources								
Power Generation by Utilities	.1	.1	.1	.1	.1	.2	.2	.2
Res/Commercial	.1	.1	.1	.1	.1	.1	.1	.0
Industrial	.1	.1	.1	.1	.1	.1	.1	.1
Transportation[3]								
Light-Duty Vehicles	.3	.3	.4	.4	.4	.3	.3	.3
Heavy-Duty Vehicles	.1	.1	.1	.1	.2	.2	.2	.2
Rail	.1	.1	.1	.1	.1	.1	.1	.1
Other Diesel	.1	.1	.1	.1	.1	.1	.1	.2
Other (Air, Marine, Off-Road Gasoline)	.1	.1	.1	.1	.1	.1	.1	.1
TOTAL	1.0	1.0	1.1	1.1	1.2	1.2	1.2	1.2

NOTES:

1. Expressed as NO_2.
2. Eastern Canada comprises the provinces east of the Saskatchewan/Manitoba border.
3. The emissions estimates presented for the light-and heavy-duty vehicles sector were calculated using the US EPA Mobile 3 road transportation model modified to reflect Canadian conditions. Previous reported estimates were made using a Canadian version of Mobile 2 and should not be compared with those presented here.

References for Tables 5 and 6:

1. Emissions and Trends of Common Air Contaminants in Canada, 1970-80, Report EPS7/AP/17, September 1986.

2. General Methods for preparing an annual sulphur dioxide emissions inventory for sources in Eastern Canada. Report P-5134/FG. November 1986. Report prepared under contract by the Ontario Research Foundation.

3.2 ATMOSPHERIC CHEMISTRY

3.2.1 Urban Scale Effects

Detailed chemical and meteorological observations around Philadelphia during selected storm events led to two conclusions:

1. Nitrate and sulfate deposition were significantly elevated downwind from the urban area. In these storms wet nitrate and sulfate deposition continued to increase for at least 60 km (36 mi.) from the city. (Measurements were not taken more than 60 km from the city).

2. Data from some winter storms demonstrated that low levels of oxidants may limit the oxidation of sulfur dioxide to sulfate and nitrogen oxides to nitrate.

Reference:

Patrinos, A.A.H. 1985. Impact of Urban and Industrial Emissions on Mesoscale Precipitation Quality. Journal of the Air Pollution Control Association. 35: 719-727.

3.3 ATMOSPHERIC MODELING AND TRANSPORT

3.3.1 Tracer Experiments

Large scale experiments with inert tracer gas releases from Dayton, Ohio, and Sudbury, Ontario, showed that simple trajectory long-range transport (LRT) models can perform well under the uncomplicated meterological situations selected (e.g., no storms). For example, AES-LRTAP model (a Lagrangian model) trajectories, at a height of 925 mb, accurately simulated the speed and direction of the tracer transport for at least the first 24 hours and thus provided additional confidence in one of the most important components of a simple model used as a qualitative tool for estimating source-receptor relationships.

Reference:

Summers, P.W. and Olson, M.P. 1985. "A Comparison Between AES-LRTAP Model Trajectories and Observed Tracer Concentrations During CAPTEX-83", International Symposium on Acid Precipitation, Muskoka, Sept. 15-20, 1985.

3.3.2 Model Intercomparison

Canada and the United States jointly conducted the International Sulfur Deposition Model Evaluation (ISDME) Project to evaluate the performance of eleven linear-chemistry atmospheric models of sulfur deposition against seasonal and annual 1980 observations of sulfur wet deposition. The evaluation focused on the comparison of patterns of predictions and observations interpolated by kriging, since kriged patterns, rather than site measurements, best represent regional deposition. Kriging also quantifies the uncertainties about the pattern due to measurement errors and interpolation uncertainties, which include uncertainties arising from the fact that site measurements are not necessarily regionally representative. The interpolated

SULPHATE — ANNUAL

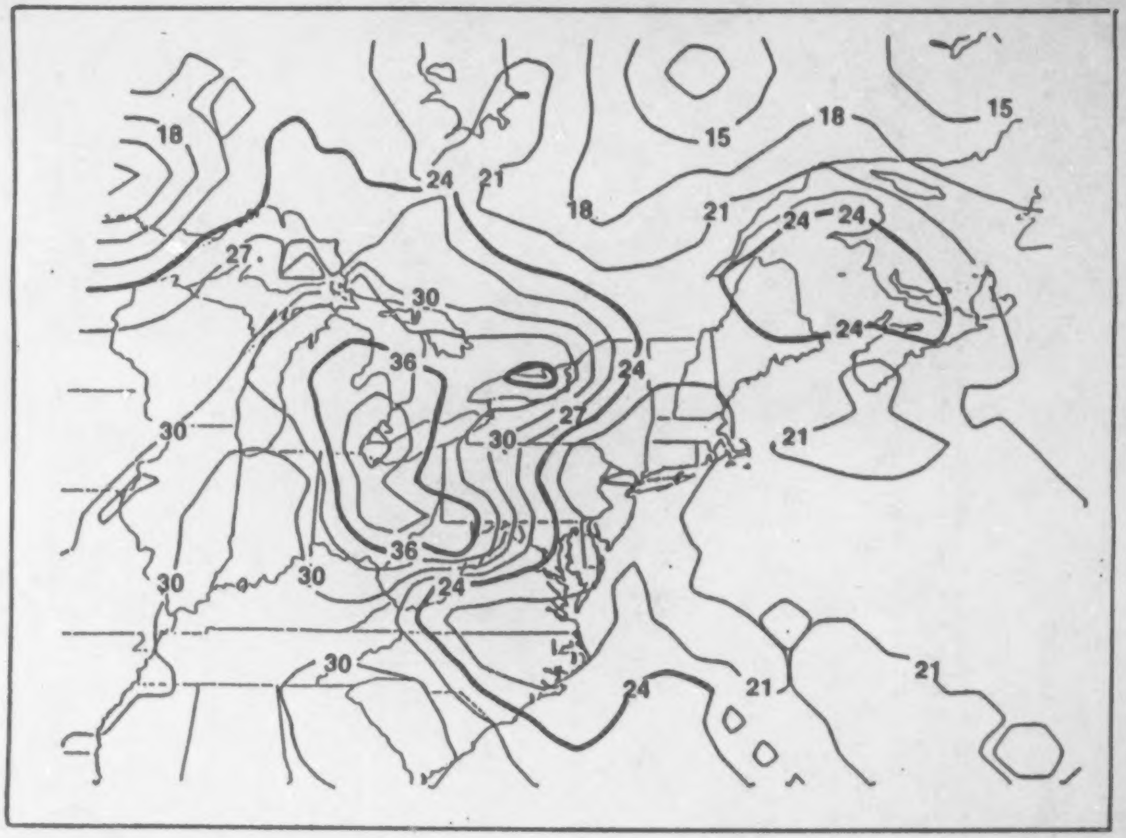
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Figure 2: 1980 sulphate deposition in precipitation. (kg/ha/yr).

AES — ANNUAL

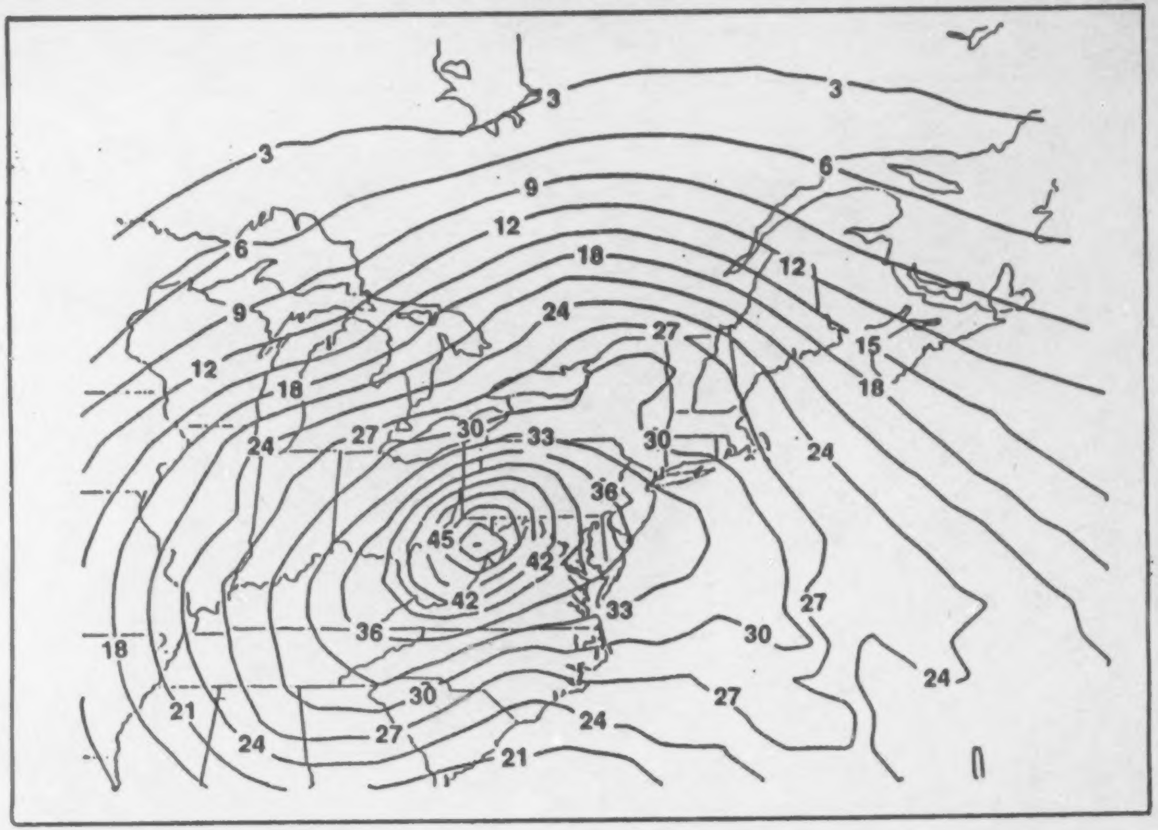
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Figure 3: AES model prediction of 1980 sulphate deposition in precipitation. (kg/ha/yr)

ASTRAP -- ANNUAL

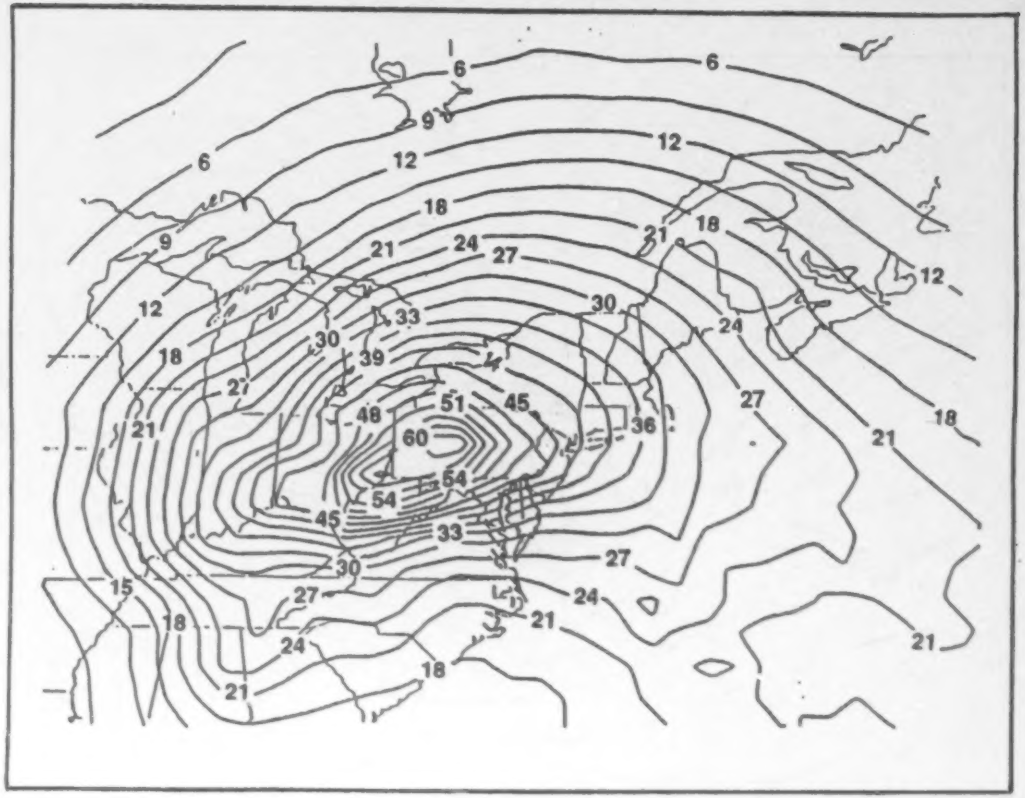
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Figure 4: ASTRAP model prediction of 1980 sulphate deposition in precipitation. (kg/ha/yr)

pattern of annual observations across the evaluation region is shown in Figure 2 and several predicted annual patterns are shown in Figures 3 and 4.

The development and application of new spatial statistical evaluation procedures including uncertainty effects, provided sufficient information to establish the following results:

1. Model prediction patterns are generally elliptic in shape; secondary peaks in the interpolated patterns of observed wet deposition are generally not reproduced by the model predictions.

2. The model predictions of wet sulfur deposition more closely resemble the seasonal emissions patterns than the seasonal patterns of the interpolated wet deposition amounts. Specifically, the predictions of maximum deposition coincides with the region of highest emissions. Depending on the model, distances separating the predicted and observed locations of the wet deposition maxima for each season were within 170 to 350 kilometers.

3. For six of the eleven models, the seasonal mean predictions of sulfur wet deposition across the high deposition region are within +/-50% of the seasonal means of the interpolated observations.

4. The uncertainties are as high as +/-50% across the area of greatest site density and are higher elsewhere. Coupled with the fact that the magnitude of the observed sulfur wet deposition across the evaluation region varies by only a factor of two, models in this study are afforded a large statistical tolerance for differences.

5. Across at least 80% of the evaluation area:

    a. The seasonal estimates of sulfur wet deposition of five of the eleven models were within the uncertainty limits of the interpolated patterns of observations,

    b. The seasonal estimates of all but three models were within the same uncertainty limits for at least three seasons, and

    c. The annual estimates of all but three models were within the same uncertainty limits.

The uncertainties of the patterns, which are related to site density, should be lower for subsequent years when more sites exist. The reduced uncertainties will make possible more rigorous evaluations in the future.

References:

Dennis, R.L. and S.K. Seilkop. 1986. The use of spatial patterns and their uncertainty estimates in the model evaluation process. Proceedings of the Fifth Joint Conference on Applications of Air Pollution Meteorology, Chapel Hill, NC, November 18-21, 1986.
pp. 41-44.

Clark, T.L., et.al. 1986. The international sulfur deposition model evaluation. Proceedings of the Fifth Joint Conference on Applications of Air Pollution Meteorology, Chapel Hill, NC, November 18-21, 1986. pp. 57-60.

3.4 DEPOSITION MONITORING

3.4.1 Trends in Wet Concentration

Precipitation chemistry data from 19 NADP locations in the United States with the longest records (1978-83) were analysed by the U.S. Geological Survey. They show a preponderance of downward trends for sulfate (Figure 5), nitrate (Figure 6), sodium and chloride concentrations. Most sites showed no trend for ammonia, potassium and pH.

In its examination of trends (but for a shorter time period) the National Academy of Sciences concluded that:

> On the basis of preliminary analyses of CANSAP-APN and NADP data for the eastern half of the continent, changes in anthropogenic emissions during the period 1979-1982 are not readily apparent; concentration changes from year-to-year occur concurrently in both anthropogenic and natural constituents and are thought to be more strongly affected by meteorological rather than emissions changes during this period.

References:

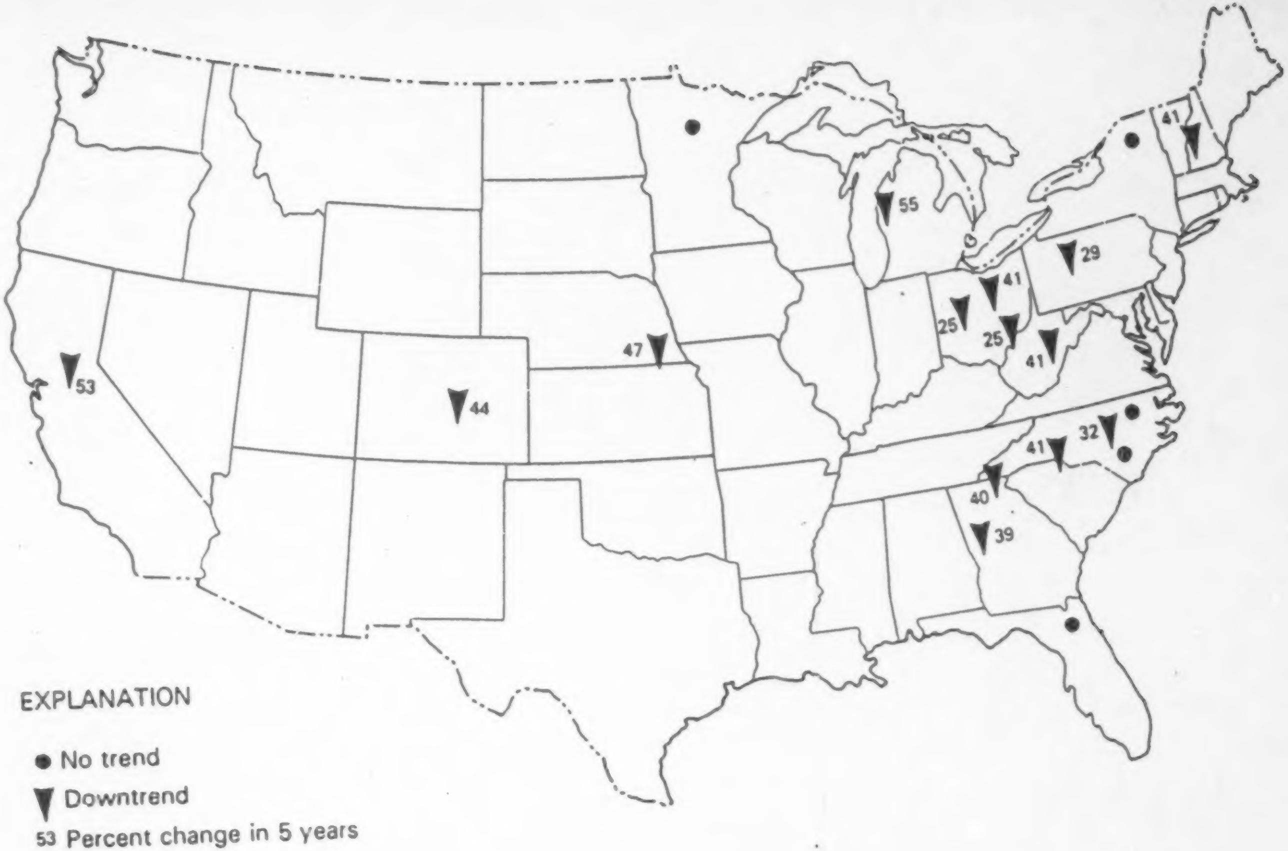
Schertz, T.L. and R.M. Hirsh. Trend Analysis of Weekly Acid Rain Data--1978-83. USGS. Water Resources Investigations Report 85-4211, United States Geological Survey, Denver, CO. 1986. 67 pp.

U.S. National Academy of Sciences. "Acid Deposition: Long Term Trends" Chapter 5, Washington, DC 1986, 506 pp.

3.4.2 Dry Deposition

3.4.2.1 United States

First results from a trial program for deriving gaseous and particulate sulfur dry deposition are shown in Figure 7. The figure compares preliminary dry and wet deposition estimates of sulfur for the lower slope of Whiteface Mountain in New York. In general, wet deposition appears to exceed dry deposition at the site.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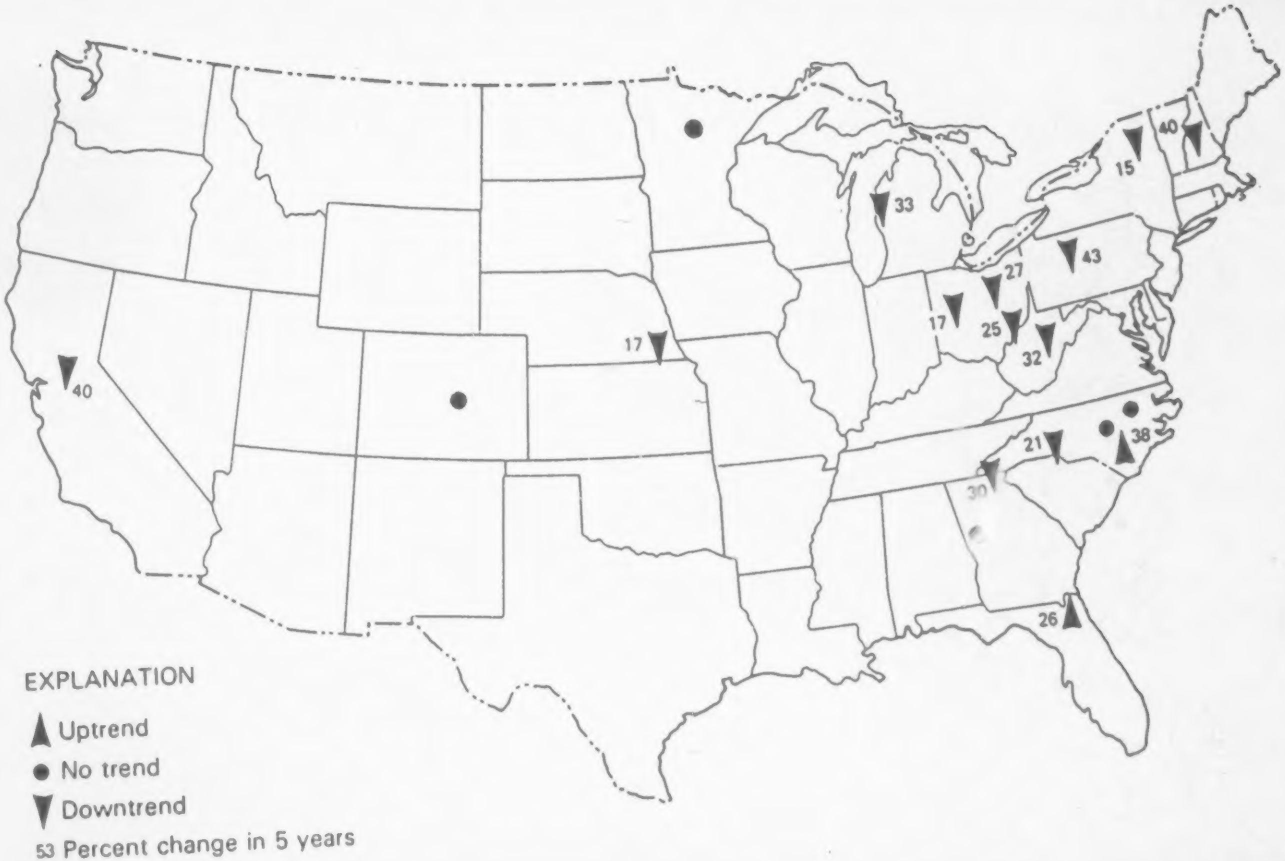
EXPLANATION
● No trend
▼ Downtrend
53 Percent change in 5 years

Figure 5: Trends in sulfate concentration of precipitation: 1978-83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▲ Uptrend
● No trend
▼ Downtrend
53 Percent change in 5 years

Figure 6: Trends in nitrate concentration of precipitation: 1978-83

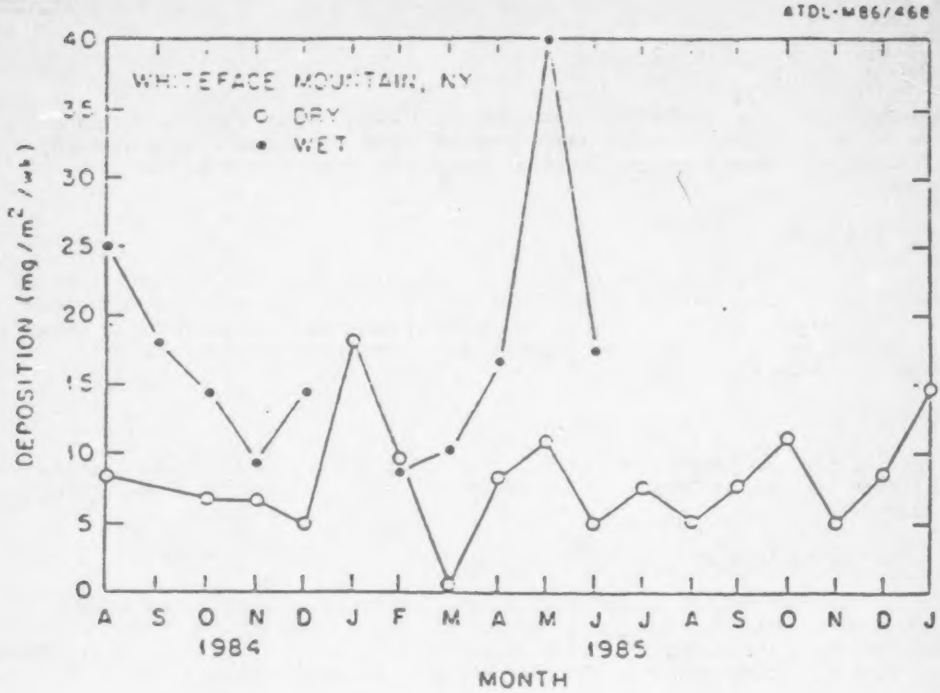


FIGURE 7 — Preliminary estimates of wet and dry (gases and particles) deposition of sulfur at Whiteface Mountain, NY.

Reference:

Hicks, B.B., R.P. Hosker, J.D. Womack (in press). Comparison of wet and dry deposition derived from the first year of trial dry deposition monitoring. Proceedings of an American Chemical Society Symposium on Acid Rain. April 1986.

3.4.2.2 Canada

Analyses of precipitation and air chemistry data indicate that at 5 stations in eastern Canada (Manitoba and east) the estimated dry deposition of sulfur ranges from 14 to 26% of the total. However, in southwestern Ontario closer to major SO_2 emission regions, dry deposition accounts for approximately 40% of the total.

Reference:

Barrie, L.A. and Sirois, A. 1986. "The Wet and Dry Deposition of Sulfate and Nitrate in Eastern Canada: 1979-1982", J. Water, Air and Soil Pollution. 30:303-310.

3.4.3 Cloud Chemistry

Canada and the United States have initiated closely coordinated programs to determine wet, dry, and occult deposition at high mountain elevations. These projects were initiated because of reports of forest damage at high elevation and where forests are most exposed to cloud water.

The first comprehensive results reported recently from the continuous monitoring station at Whiteface Mountain, New York, are probably representative of high elevation rural air over the northeastern U.S. These results provided insight regarding the seasonal differences in average ozone concentrations, and levels of SO_2, and NO_x relative to ozone, and the importance of H_2O_2 in the oxidation of SO_2 to sulphate in the summer.

3.4.3.1 Canada

Preliminary data from the Canadian sites of the high elevation fog study indicate that the pH of fogwater can be as low as 3.4. During the period August-December 1985, 20 fog samples were collected at the summit of Mt. Tremblant (Central Quebec, 115 km (70 miles) north of the St. Lawrence River, elevation 860m 2800 feet). The mean pH of the fogwater was 3.8 with a range from 3.4 - 5.0. During the same period, 4 fog samples were obtained from Roundtop Mountain (Southern Quebec near Canada-U.S.A. border, elevation 845 m . 2770 feet). The mean pH was 3.7 with a range from 3.4-4.4. Subsequent 1986 sampling shows similar values.

Reference:

Schemenauer, R. 1986. Acidic Deposition to Forests: The 1985 Chemistry of High Elevation Fog (CHEF) Project, Atmosphere Ocean, 24:303-328.

TABLE 7

Seasonal data for Whiteface Mountain:

	WINTER	SUMMER
SO_2 (gas phase)	1983-1984 - monthly averages (Dec-Feb) are 3 to 7 ppbv (8 to 18 ug/m^3) - monthly maxima range from 10 to 60 ppb (26 to 160 ug/m^3)	Polluted episodes: 4 ppb (10 ug/m^3) Clean episodes: 0.3 ppb (1 ug/m_3) Av. Growing Season 1.3 ppb (3 ug/m^3)
NO_x (gas phase)	1983-1984 - monthly averages are 4 to 6 ppbv (8 to 11 ug/m^3) - monthly maxima are 24 or 26 ppbv (45 or 49 ug/m^3)	Polluted episodes: 6 ppb (12 ug/m^3) Clean episodes: < 1 ppb (2 ug/m^3) Av. Growing Season 3 ppb (6 ug/m^3)
H_2O_2 (aqueous and gas phases)	- almost always less than 100 ppb the aqueous phase	- 3000 ppb in the aqueous phase
	- ~ .1 ppb in the gas phase (.1 ug/m^3)	- up to 3 ppb (4 ug/m^3) in the gas phase
O_3 (gas phase)	1973-1985 ~ 33 ppb (hourly average) (66 ug/m^3)	1973-1985 ~ 44 ppb (88 ug/m^3) (hourly average)

REFERENCE:

Kadlecek, J., J. McLaren, V. Mohnen, B. Mossl, A. Kadlecek, and N. Camarota, March 1985 Wintertime Cloudwater Chemistry Studies, Whiteface Mountain 1982-1984. Empire State Electronic Energy Research Corporation. Report 82-10, March 1985.

Kadlecek, J.A., S. McLaren, V.A. Mohnen, and A. Lazrus. Cloud Water Chemistry, Winter-Summer Comparison at Whiteface Mountain. Second International Speciality Conference on Meterology of Acidic Deposition (eds.) J. Lazrow and G.J. Stensland. Air Pollution Control Association, March 1986.

V.A. Mohnen, R.L. Bradow, D. Landsberg, J. Healey, and B.H. Bailey Jan. 1987. Overview of the EPA Mountain Cloud Chemistry Program. Proceedings of the Sixth Symposium on Meterological Observations and Instrumentation.
Kelly, Thomas J., R.L. Tanner, L. Newman, P. Galvin, J.A. Kadlecek. 1984. Trace Gas and Aerosol Measurements at a Remote Site in the Northeastern U.S. Atmospheric Environment.

3.4.3.2 United States

Measurements of wintertime cloud chemistry at Whiteface Mountain, NY (see Table 7) show elevated levels of SO_2 and NO_x, low levels or absence of a strong oxidant, and the dominance of nitrate rather than sulfate anions. These observations contrast with summertime observations where SO_2 and NO_x concentrations are lower, sulfate dominates and H_2O_2, a strong oxidant, is abundant. This is consistent with the understanding that wintertime oxidation of SO_2 to sulfate is often limited by the unavailability of sufficient aqueous phase oxidants. The ozone concentration in the clear air at this site is about 50% higher in April-Sept. than October-March and 100% higher in May-June than Dec.-Jan., consistent with the seasonal oxidant concentration in the clouds.

Reference:

Kadlecek, J., J. McLaren, V. Mohnen, B. Mossl, A. Kadlecek, and N. Camarota, March 1985 Wintertime Cloudwater Chemistry Studies, Whiteface Mountain 1982-1984. ARSC Research Report EP82-10. Ozone data from V. Mohnen, Atmospheric Sciences Research Center, State University of New York, Albany, NY.

3.5 AQUATIC EFFECTS

3.5.1 Streams Trends

3.5.1.1 Nova Scotia and Newfoundland

Sulphate concentrations have decreased in 12 Nova Scotian and 8 Newfoundland rivers between the early 1970's and early 1980's (Table 8). There has been a corresponding increase in the pH of the rivers.

Reference:

Thompson, Mary E., 1986. Chemical Trends in Coastal Rivers in Eastern Canada. NWRI, Burling, Ontario, Canada (in press). Martin, H.C. and T.G. Brydges, 1986. Stress Factors: Trends and Recovery. The International Conference on Acidification and its Policy Implications, Amsterdam.)

3.5.1.2 United States Benchmark Stream Trends

The National Academy of Sciences examined USGS data from Bench-mark streams for the 15 to 20 years preceeding 1983. These data provide a basis to draw conclusions about long-term trends in stream surface water chemistry.

Two benchmark streams in the northeastern U.S. show a decrease in sulfate concentrations (Figure 8) and an increase in alkalinity (Figure 9). Nine benchmark stations in the southeastern U.S. show an increase in sulfate concentrations and mixed trends in alkalinity and pH. Trends in sulfate are generally consistent with changes in emission patterns.

The National Academy of Sciences concluded that the increases in alkalinity in the northeast could be accounted for by the decrease in sulfate concentration.

TABLE 8

Sulphur Dioxide Emission Changes, Sulphate Export from 12 Nova Scotian and 8 Newfoundland Watersheds, and pH Ranges from Associated Rivers.

	1971-1973	1982-1983	Change
SO_2 Emission in Eastern * Canada and the United States (yearly averages)	27	20	-25%
Watershed Export (kgs SO_4/ha/yr)			
A Nova Scotia	39 ± 6.7	21 ± 6.1	-47%
B Newfoundland	32 ± 12	18 ± 8	-44%
pH range of river **			
A Nova Scotia	4.4 to 6.5	4.5 to 6.7	
B Newfoundland	5.5 to 7.7	6.1 to 7.8	

* Emissions are for Provinces and States are wholly or partially within 1500 km of southern Nova Scotia.

** All rivers decreased in sulphate yield and increased in pH.

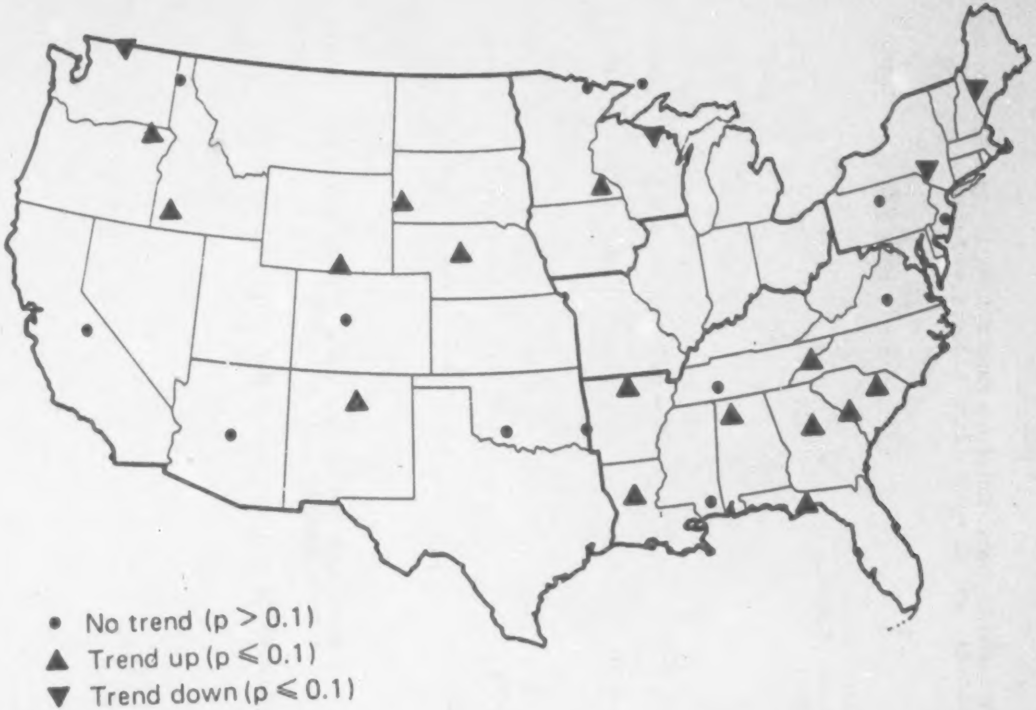

● No trend (p > 0.1)
▲ Trend up (p ≤ 0.1)
▼ Trend down (p ≤ 0.1)

Figure 8: Trends in sulfate concentration at USGS Benchmark stations where sulfate is thought to derive primarily from atmospheric sources.

(From Fig. 7.6 of Acid Deposition: Long Term Trends, National Academy of Sciences, p. 252.)

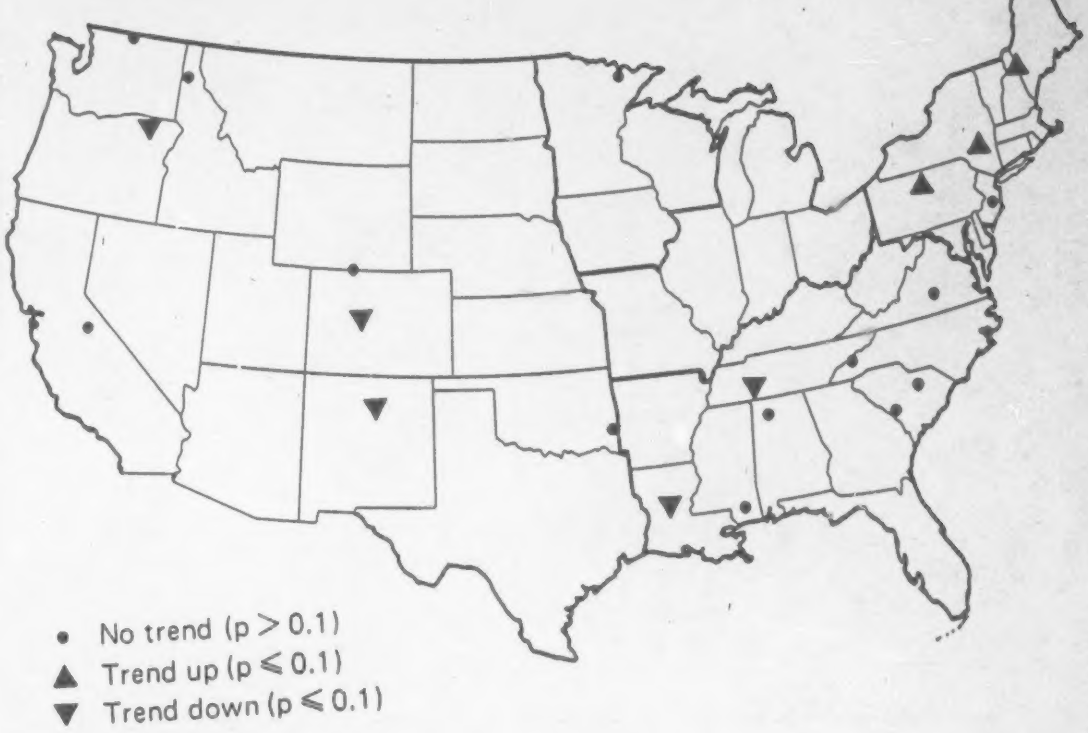
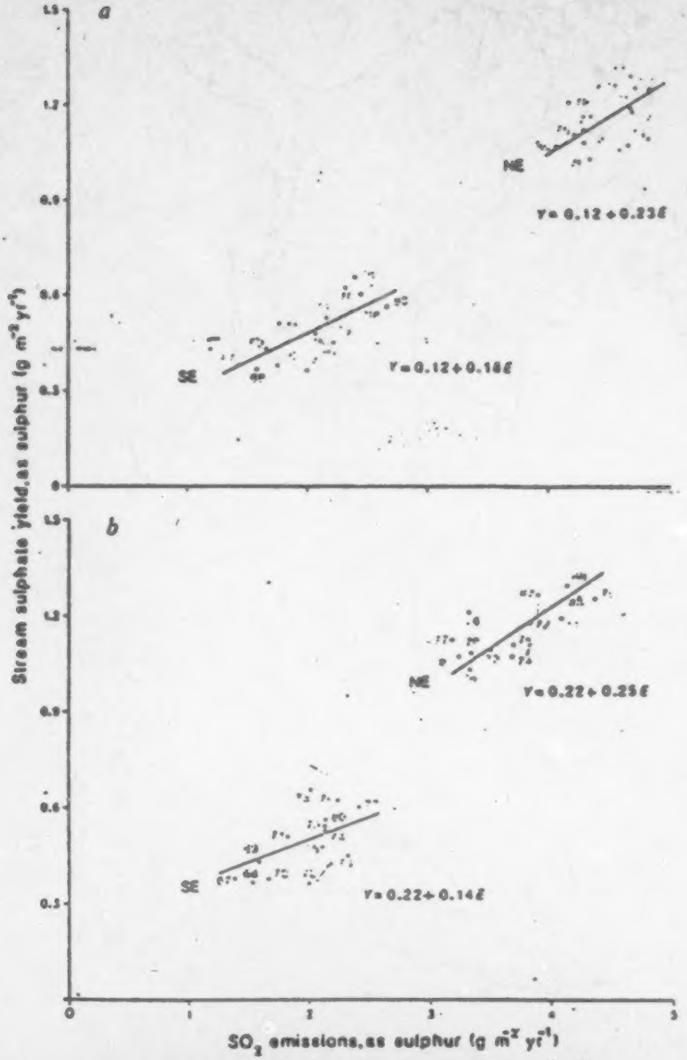

● No trend (p > 0.1)
▲ Trend up (p ≤ 0.1)
▼ Trend down (p ≤ 0.1)

Figure 9: Trends in alkalinity at USGS Benchmark stations.

(From Fig. 7.7 of Acid Deposition: Long Term Trends, National Academy of Sciences, p. 254)

FIGURE 10



Average stream yield (Y) of SO_4 at USGS Benchmark stations in the eastern United States, plotted against regional SO_2 emission density (E) for the years 1967–80 (shaded numbers). Plots are presented for two recent sets of emission estimates[8,9], based on alternative methods of estimating the sulphur content of combusted fuels (a, production-driven emissions[8]; b, consumption-driven emissions[9]). Both emissions and stream yield of sulphur decreased in the NE but increased in the SE during the 1967–80 period. Analyses of covariance for both sets of emission estimates result in a two-slope, one-intercept model with smaller slopes for the SE than for the NE. All slopes are significant at $\alpha = 0.01$. Intercepts are not significantly different from zero at $\alpha = 0.05$.

From Smith and Alexander.

Reference:

Kramer, J.R., A.W. Andren, R.A. Smith, A.H. Johnson, R.B. Alexander, and G. Oehlert. 1986. Streams and lakes. pp. 231-299 in: Acid Deposition, Long Term Trends. National Academy Press, Washington, D.C. 506 pp.

3.5.1.3 USGS Benchmark Stream Yield and Emissions

Correlations between regional emissions of SO_2 (the emissions were from the states shown in Figure 11) and stream sulfate content in USGS Benchmark streams (See Figure 10) have been found in the northeastern and southeastern United States. Regression analysis suggests that a reduction in regional emissions would lead to a nearly proportional reduction in stream sulfate yield.

Reference:

Smith, R.A. and R.B. Alexander. 1986. Correlations between Stream Sulphate and Regional SO_2 Emissions. Nature 322(6081):722-724.

3.5.2 Lakes

3.5.2.1 Surveys

Surveys describe the status of lakes, but alone cannot be used to determine the factors contributing to changes in lake chemistry.

3.5.2.1.1 Background on United States Surveys

The Eastern and Western U.S. Lake Survey provided the first reliable synoptic snapshot of U.S. lake chemistry in areas most likely to be sensitive to acidic deposition. 1,612 statistically representative lakes in the east and 719 statistically representative lakes in the west were sampled during fall turnover in the first phase of the multiphase National Surface Water Survey (NSWS). The survey collected water samples which were analyzed with extensive quality assurance and quality control for 25 chemical variables. Other components of the NSWS are examining other parts of the country, or a smaller number of lakes in greater detail.

3.5.2.1.1.1 Eastern Results - United States

Figure 12 shows the regions sampled, Tables 9 and 10 summarize the chemistry of those regions, and Figure 14 compares the chemistry of all of the subregions.

The subregion showing the highest percentage of acidic lakes in the northeastern region is the Adirondacks (1A). Ten percent of the lakes sampled in the Adirondack subregion were acidic (i.e. had a pH <5.0). This region has high aluminum values and was the only region sampled in which sulfate was the dominant anion (based on median concentrations). Weathering of sulfide minerals is not thought to be important on a regional basis. Other subregions within the northeast had a lower percentage of acidic lakes, higher ANC, lower sulfate and lower aluminum concentrations.

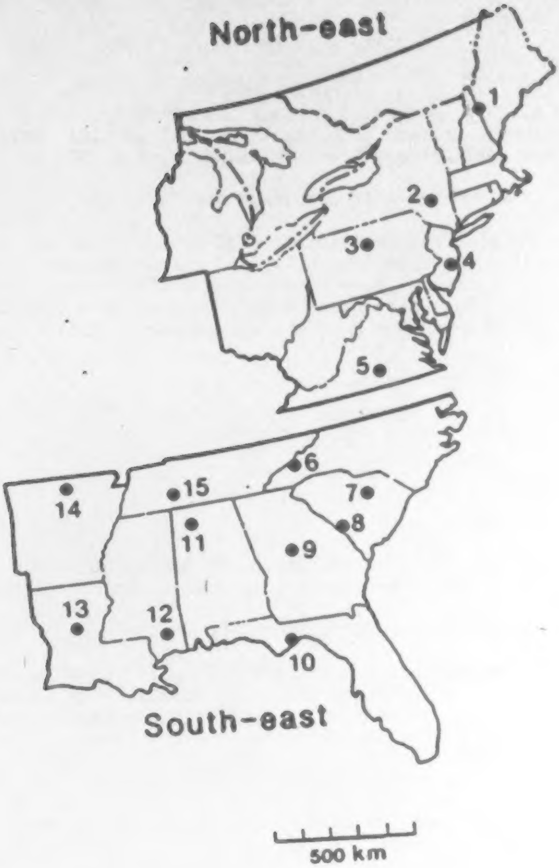

North-east
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
South-east
500 km

Figure 11.--Location of USGS benchmark streams used to develop the relationship between emissions and stream sulfate yield.

(From Smith and Alexander.

TABLE 9: ESTIMATED VALUES OF pH, ACID NEUTRALIZING CAPACITY AND SULFATE BELOW WHICH TWENTY, FIFTY AND EIGHTY PERCENT OF THE LAKESa ARE EXPECTED TO FALL WITHIN REGIONS AND SUBREGIONS. DATA ARE FROM PHASE I OF EPA'S WESTERN LAKE SURVEY

Region/Subregion	pH			Acid Neutralizing Capacity (ueq L^{-1})			Sulfate (ueq L^{-1})		
Name[b]	20%	50%	80%	20%	50%	80%	20%	50%	80%
Northeast									
Adirondacks	5.6	6.7	7.1	14	112	251	104	119	142
Catskills/Poconos	6.6	7.0	7.4	102	297	531	118	159	221
Cent. New England	6.3	6.8	7.3	52	120	388	78	101	136
South New England	6.2	6.8	7.1	39	162	403	108	141	190
Maine	6.6	6.9	7.3	72	148	298	56	75	88
Mean	6.3	6.9	7.3	52	158	400	79	115	165
Upper Midwest									
NE Minnesota	6.6	6.9	7.3	98	185	403	47	63	84
Upper Peninsula of Michigan	6.1	7.1	7.8	56	284	1284	50	78	104
N. Cent. Wisc.	5.8	6.7	7.5	16	94	601	42	57	76
Upper Gr. Lakes	6.6	7.4	8.1	104	802	2022	29	50	85
Mean	6.4	7.1	7.9	79	360	1416	35	57	88
So. Blue Ridge	6.7	7.0	7.3	150	250	421	20	32	60
Florida	5.4	6.6	7.4	-8	84	713	28	94	272

[a] Lakes >4 ha and <2000 ha.

[b] Consult Fig. 13 for actual area surveyed.

TABLE 10: ESTIMATED VALUES OF pH, ACID NEUTRALIZING CAPACITY AND SULFATE BELOW WHICH TWENTY, FIFTY AND EIGHTY PERCENT OF THE LAKESa ARE EXPECTED TO FALL WITHIN REGIONS AND SUBREGIONS. DATA ARE FROM PHASE I OF EPA'S WESTERN LAKE SURVEY

Region/Subregion	pH			Acid Neutralizing Capacity (ueq L^{-1})			Sulfate ueq L^{-1}		
Name[b]	20%	50%	80%	20%	50%	80%	20%	50%	80%
California	6.6	6.9	7.4	34	63	137	4	7	14
Pacific Northwest	6.6	7.0	7.3	52	140	293	2	15	43
Northern Rockies	6.9	7.3	8.0	69	195	1011	6	16	32
Central Rockies	6.9	7.2	7.5	65	105	207	19	24	35
Southern Rockies	7.1	7.6	8.3	114	317	1039	17	35	115
West	6.8	7.2	7.7	54	119	426	6	19	39

a Lakes >1 ha and <2000 ha

The subregion showing the highest percentage of acidic lakes in the upper midwest was the Upper Peninsula of Michigan (Subregion 2B). Ten percent of the lakes were acidic. In addition, the subregion had the highest concentrations of sulfate in the region. However, because there is a relatively large population of high ANC lakes in the subregion, median values of pH (7.10) and ANC (283.6 ueq L^{-1}) are high relative to other subregions.

Dissolved organic carbon (DOC) concentrations did not correlate with the distribution of acidic or low ANC lakes. In the Northeast, for example, 80% of the lakes contained concentrations of DOC <7 mg/L. In this region, as well as other regions sampled, a positive relationship existed between pH and DOC (i.e., high DOC and high pH) in high ANC lakes.

Reference:

Linthurst, R.A., et.al. Characteristics of Lake Population in the Eastern-United States. Volume I: Population Characteristics and Physico-Chemical Properties. EPA/600/4-86/007a, U.S. Environmental Protection Agency, Washington, DC. 1986. 136 pp.

3.5.2.1.1.2 Western United States Results

Even though the WLS-I map population consisted of lakes in areas thought to be potentially susceptible to acidic deposition, no lakes with a pH of 5.0 or less were found except for one naturally acidic lake in Yellowstone Park. To estimate relative sensitivity to acidification, reference values for ANC (50 ueq L^{-1} and 200 ueq L^{-1}) were selected. The number and percentage of lakes in each subregion and in the west as a whole at or below these specific values are summarized in Table 10. California had the largest number and percentage of lakes with ANC <50 ueq L^{-1}, followed by the Pacific Northwest (4B), the Northern Rockies, the Central Rockies (4D), and the Southern Rockies. These results are largely related to the local geology. The lower average ANC of the lake samples in California over other mountainous western states may be the result of the greater pollution level and therefore acidic deposition over recent decades.

Comparison between Wilderness and Non-Wilderness Lakes

Of the 719 lakes used in characterizing the western lake resource, 455 (63.3%) were located in wilderness areas. To determine if the chemistry observed in wilderness area lakes as a group differed from that observed for lakes located outside wilderness areas, cumulative frequency distributions for each subpopulation were compared. Two of the variables selected for comparison were ANC and sulfate (Figure 13).

As a whole, wilderness areas lakes were characterized by lower ANC values than non-wilderness area lakes due probably to the fact that the wilderness areas generally include more high elevation, glaciated, terrain than the non-wilderness areas. The largest difference in the two subpopulations was observed in the Southern Rockies, and the smallest, in the Pacific Northwest.

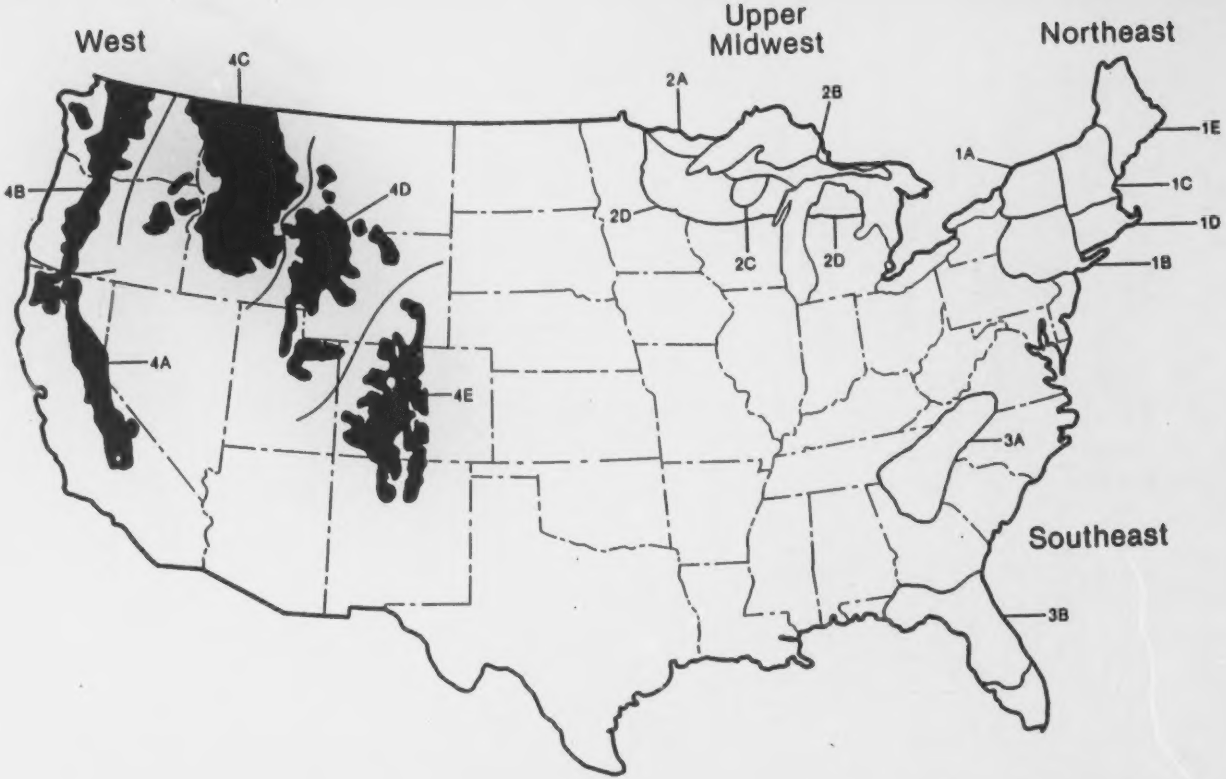

West
Upper Midwest
Northeast
Southeast
4C
4B
4D
4A
4E
2A
2B
2D
2C
2D
1A
1E
1C
1D
1B
3A
3B

Figure 12: Geographic regions and subregions in which Phase I of the National Lake Survey was conducted. Western subregions are shaded and eastern subregions are delineated with solid lines.

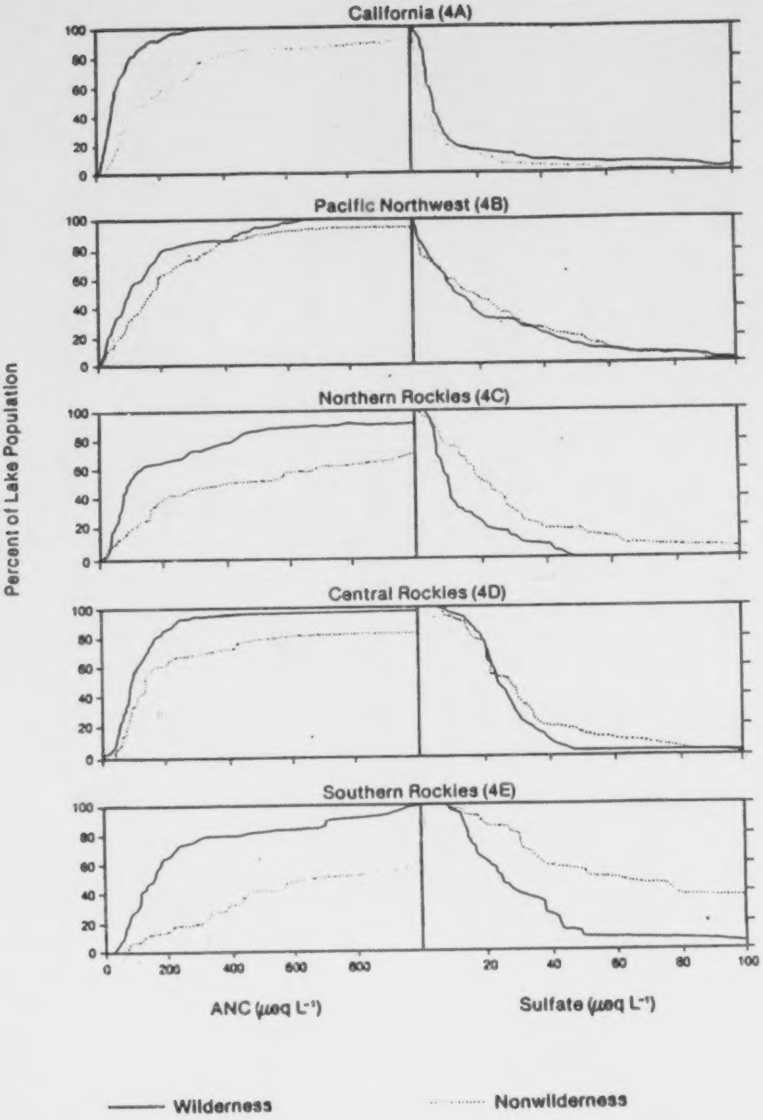


Figure 13: Cumulative frequency distributions for acid neutralizing capacity and sulfate for the target populations of wilderness and nonwilderness lakes with surface stress greater than 1 hectare and less than or equal to 2000 heactares, sampled in the Western Lake Survey - Phase I. The distance between the two curves is an indication of the degree to which the two subpopulations differ with respect to acid neutralizing capacity or sulfate.

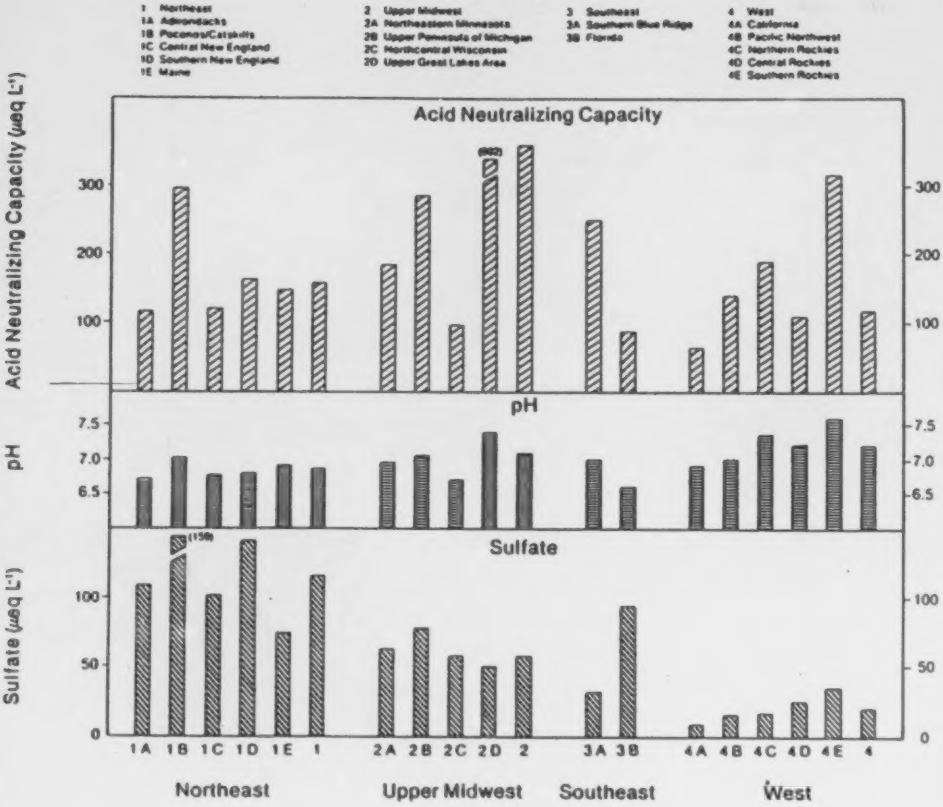


Figure 14: Median values for acid neutralizing capacity, pH, and sulfate by subregion for the Northeast, Upper Midwest, Southeast and West, for lakes in the target populations surveyed during Phase I of the National Lake Survey.

Comparison Between Eastern and Western Lakes

Median values were compared by region and subregion for ANC, pH, and sulfate (Figure 14). These estimates are based on regional target populations in the northeast of 7096, 8502 in the upper midwest, 258 and 2098 in the Southern Blue Ridge and Florida, respectively, and 10,393 in the west. The west had a lower estimated median anc than did the east. Median pH values for all eastern subregions were above 6.5, and for all western subregions were near or above 7.0.

The clearest differences between eastern and western lakes for these three variables were observed for sulfate. All median values of sulphate for western lakes were lower than those observed for any eastern subregion. This reflects the geology and the greater sulphate deposition in the east.

Reference:

Landers, D. H., J. M. Eilers, D. F. Brakke, W. S. Overton, P. E. Kellar, M. C. Silverstain, R. D. Schonbrod, R. E. Crowe, R. A. Linthurst, J. M. Omernik, S. A. Teague, and E. P. Meier. 1987. Characteristics of Lakes in the Western United States: Volume I. Population Descriptions and Physico-Chemical Characteristics. EPA/600/3-86/054a, U. S. Environmental Protection Agency, Washington, D. C.

3.5.2.1.2 Survey of Lakes in Eastern Canada

Background

Normal weathering processes will result in a ratio of alkalinity to calcium plus magnesium of unity, as observed in the northern Quebec and western and northern areas of Ontario. In the presence of acid anions such as sulfate, nitrate and organic acids, the ratio will be less than unity and the water is considered to have an "alkalinity deficit." This is observed over large areas of eastern Canada. If the ratio falls to zero or less, the water is regarded as fully acidified.

The sulfate can come from several sources such as acid mine drainage, acid spills, and acid deposition. Mine drainage and spills are local problems and not a significant contribution to the general alkalinity deficit observed in eastern Canada.

Results

Analysis of surface water chemistry based on data from about 8000 lakes shows the extensive deficit of alkalinity (Figures 15 and 16) in lakes from western Ontario eastward and south of 52° latitude. The areas of greatest alkalinity deficit correspond to the areas of greatest sulfate deposition. The deficit of alkalinity has been shown to result from the presence of sulfates. Organic acids have been ruled out as the dominant contributors to the acidification process.

References:

Jeffries, D., 1986. Ionic ratios in surface waters in eastern Canada. Report to the Economic Commission for Europe. Effects on sulphur in the environment, Work Group, Geneva, Switzerland.

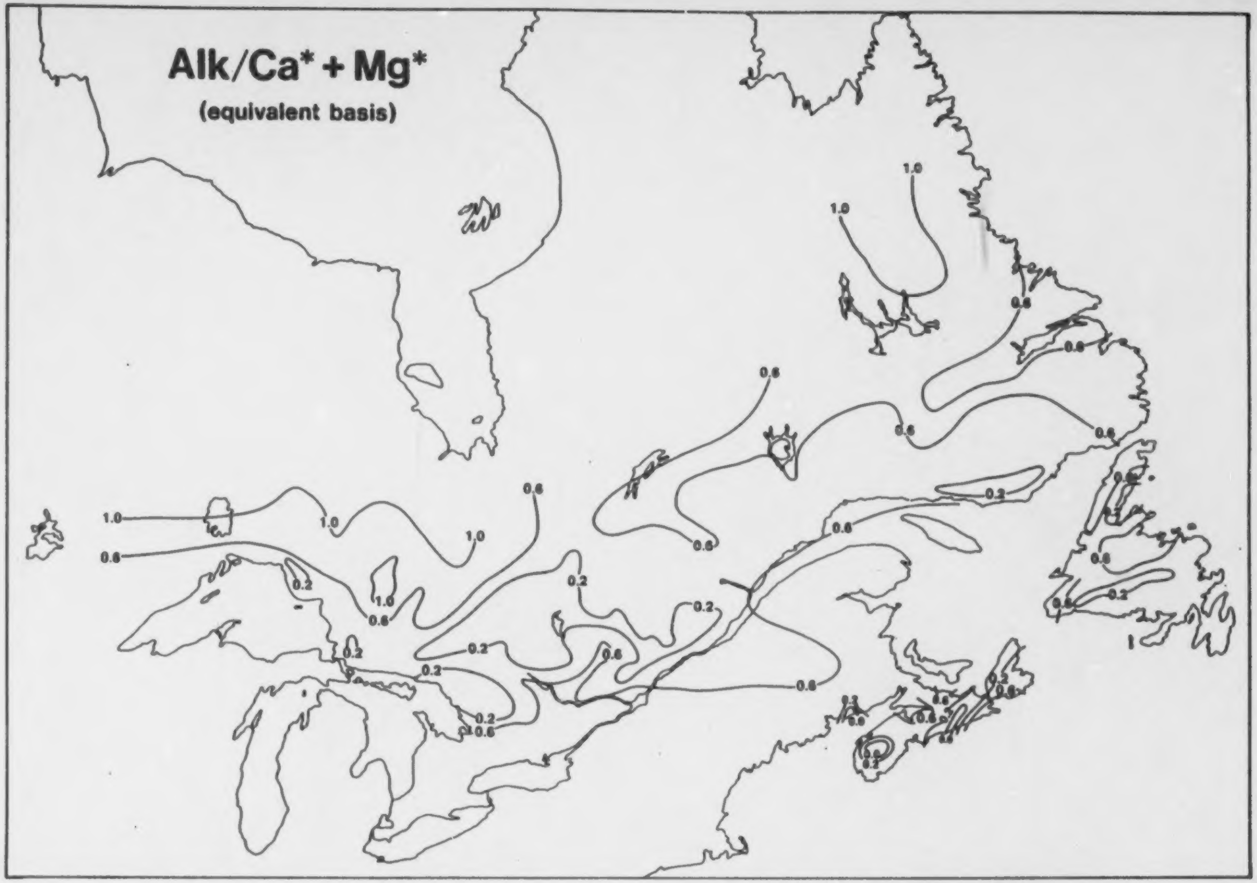

Alk/Ca* + Mg*
(equivalent basis)
1.0
1.0
0.6
1.0
1.0
0.6
0.6
0.6
0.6
0.6
0.6
0.2
0.2
0.2
0.2
0.2
0.6
1.0
0.6
0.2
0.2
0.6

Figure 15: The status of surface waters in eastern Canada as measured by the ratio of alkalinity to calcium plus magnesium. This map is based on approximately 8,000 sample points.

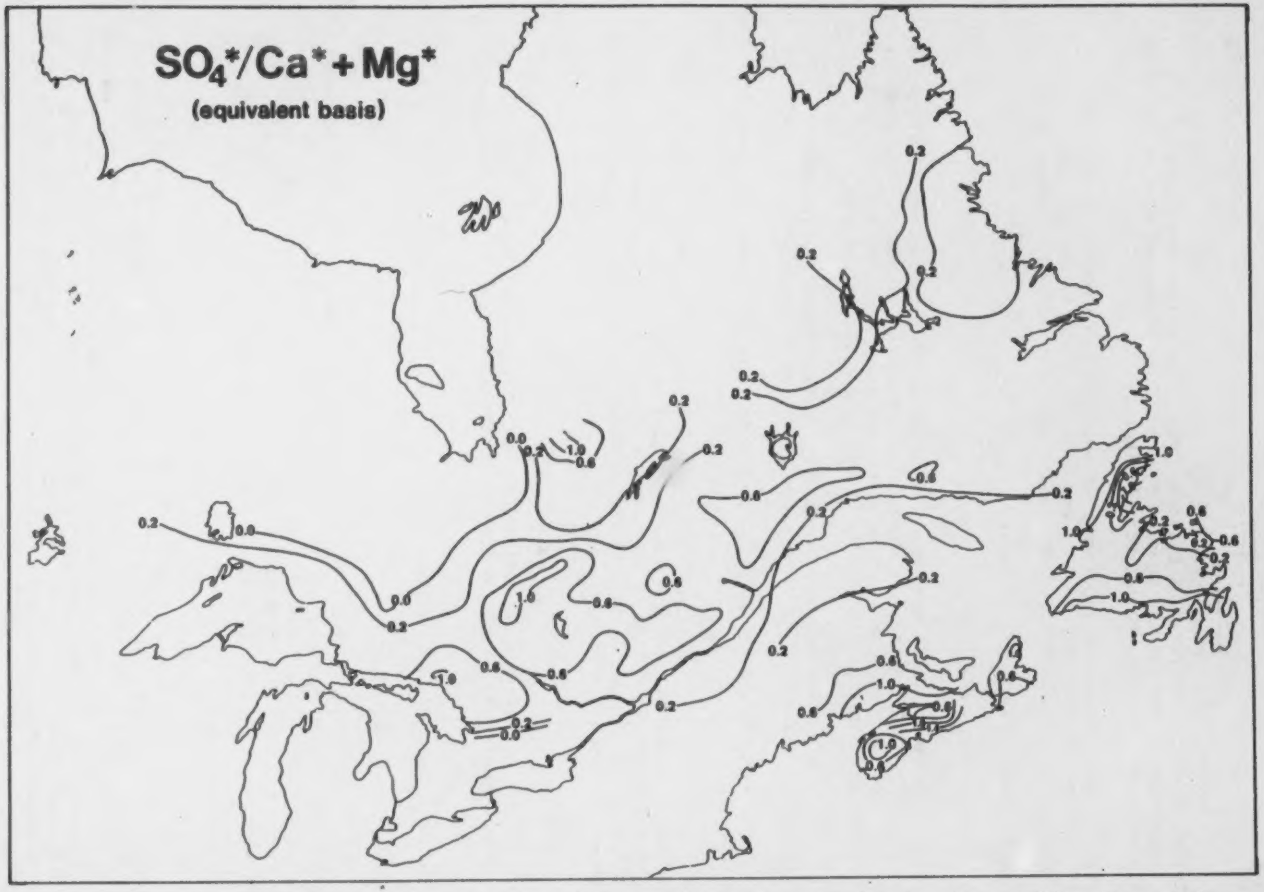

SO₄*/Ca* + Mg*
(equivalent basis)
0.2
0.2
0.2
0.2
0.2
0.2
0.0
0.2
1.0
0.6
0.2
0.6
0.6
0.2
1.0
0.6
0.2
0.6
0.6
0.2
0.0
0.2
1.0
0.6
0.6
1.0
0.2
0.0
0.2
0.2
0.6
1.0
0.6
1.0
0.6
0.6
1.0
1.0
0.6
0.2
0.6
0.2
0.6
0.2
0.6
1.0

Figure 16: Estimates for the ratio of sulphate to calcium plus magnesium for the same lakes documented in Fig. 15.

LaZerte, Bruce D. and Peter J. Dillion, 1984. "Relative importance of anthropogenic versus natural sources of acidity in lakes and streams of central Ontraio." Can. J. Fish. Aquat. Soc. 41 1664-1677.

"Brown Waters": Relative importance of external and internal sources of acidification on catchment biota. Review of Existing Knowledge LRTAP Workshop No. 5. Environment Canada and the Department of Fisheries & Oceans, March 1986.

3.5.2.2 Long-Term Trends in Lakes

3.5.2.2.1 Fifty to Sixty Year Trends

The National Academy of Sciences examined a variety of historical lake chemistry data in order to draw inferences about trends in lake chemistry over the past 50 to 60 years. They made necessary adjustments in the older data to ensure its consistency with more recent data. They found that:

1. In New Hampshire no statistically significant change in alkalinity is apparent, and the average pH may have increased.

2. The pH and alkalinity in Wisconsin lakes have increased significantly.

3. In the Adirondacks varying reasonable assumptions about the older chemical methods and the choice of 1980 or 1984 as the recent year of comparison result in different conclusions about trends in pH and alkalinity. pH and alkalinity have either remained constant or decreased by up to 0.74 pH units and 69 ueq of alkalinity.

Reference:

Kramer, J.R., et. al. and G. Oehlert. 1986. Streams and lakes. pp. 231-299 in: Acid Deposition, Long Term Trends. National Academy Press, Washington, DC. 506 pp.

3.5.2.2.2 Sudbury Area Trends

3.5.2.2.2.1 Chemistry

Water chemistry in the Sudbury area has shown major decreases in sulphate concentrations and substantial increases in pH and alkalinity since the early 1970's when large local SO_2 emission reduction programs were implemented. Data for one study lake, Clearwater Lake, is shown in Figure 17. Data for a population of lakes near Sudbury is given in Figure 18.

3.5.2.2.2.2 Fisheries

"Joe Lake, 28 km north of Sudbury, currently supports a self-sustaining brook trout (Salvelinus fortinalis) population resulting from restocking in 1977. The natural brook trout population of Joe Lake disappeared during the late 1950's or early 1960's and stocking of species in 1959 and 1966 were unsuccessful... Whitepine Lake, 90 km north of Sudbury, until very recently contained only a remnant native lake trout (Salvelinus namaycush) population consisting of a very small number (approx. 15) of large adults.

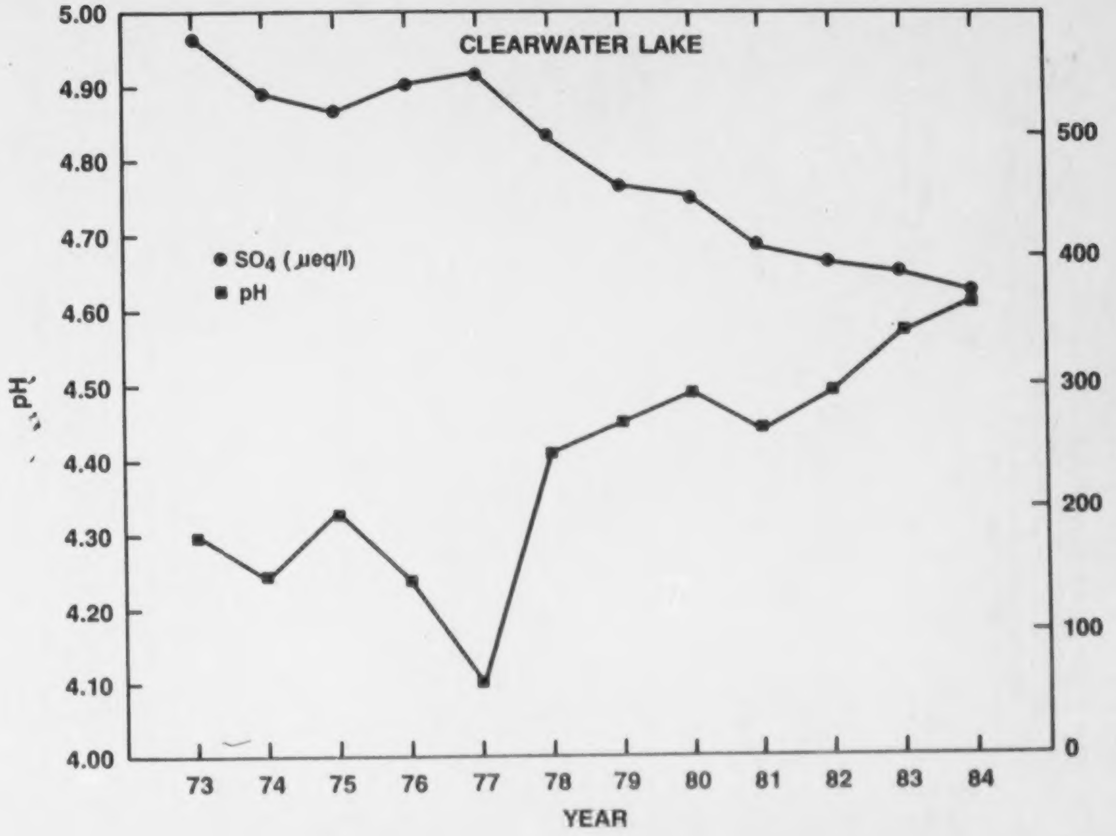


FIGURE 17 -- Trends in sulphate and pH values for Clearwater Lake, Ontario.

During 1982, native lake trout fingerlings were observed, the first evidence of natural recruitment documented in the lake during the last decade (Gunn and Keller, 1984). Additional anecdotal information ...; and conversations with local residents) suggests improvement in fisheries for other Sudbury area lakes." (From Keller and Pittblato, 1986)

Reference:

Dillon, P.J., R.A. Reid and R. Girard, 1986. Changes in the Chemistry of Lakes Following Reductions of SO_2 Emissions. Water, Air and Soil Pollution (in press).

Keller, W. and J. Roger Pittblado, 1985. Water Quality Changes in Sudbury Area Lakes, 1974-76 to 1981-83, Acid Precipitation in Ontario Study report #007/85, Ontario Ministry of the Environment, Toronto, Ontario, Canada.
Gunn, J.M. and W. Keller, 1984. Spawning site water chemistry and lake trout (Salvelinus namaycush) sac Fry Survival during spring snowmelt. Can. J. Fish. Aquat. Sci., 41:319-329.

3.5.3 Manipulation of Sensitive Watersheds

Preliminary results from the RAIN (Reversing Acidification in Norway) project have indicated that reductions in acid deposition to a very sensitive (e.g., a watershed with thin soils, and minimal vegetation) acidified terrain led to a rapid response in runoff chemistry. Within one year of reducing deposition, sulphate concentrations decreased by about 1/2 of the calculated long-term reduction. Nitrate concentrations in the runoff decreased more quickly than the sulfate concentrations. At a second experimental location, addition of nitric and sulphuric acids to sensitive non-acidified terrain resulted in a rapid increase in sulphate concentrations and associated acidity in runoff. The added nitrate was almost entirely retained in the catchment although concentrations in runoff were high during the acid treatments.

Reference:

Wright, Richard F. and Egil Gjessing. RAIN Project, Annual Report for 1985, Oslo, May 1986.

3.5.4 Groundwater

Recent measurements of shallow groundwater (less than one metre) have shown acidification by mineral acids. Results for the Turkey Lake study location (Algoma, Ontario) are shown in Figure 19. Data from the period March 8-June 5 show that sulphate is the dominant anion at all times and under conditions of heavy spring rains (March 27) and spring runoff (April 19) the alkalinity is exhausted. On the April 19 spring runoff sampling, nitrate contributed about 30% of the total anion concentrations. During the other sampling dates, the nitrate contribution to the anions was negligible. The soil water contributes to the chemical quality of the streams and lakes and the observations are consistent with the fact that the lakes in the area suffer an alkalinity deficit of about 80%. In otherwords, data show that the degree of soil and surface water acidification are consistent with one another.

Reference:

Johnston, L. 1986. National Hydrology Research Institute, Saskatoon, Saskatchewan, presentation at the International Symposium on Acidic Precipiration, Muskoka, Canada, 1985.

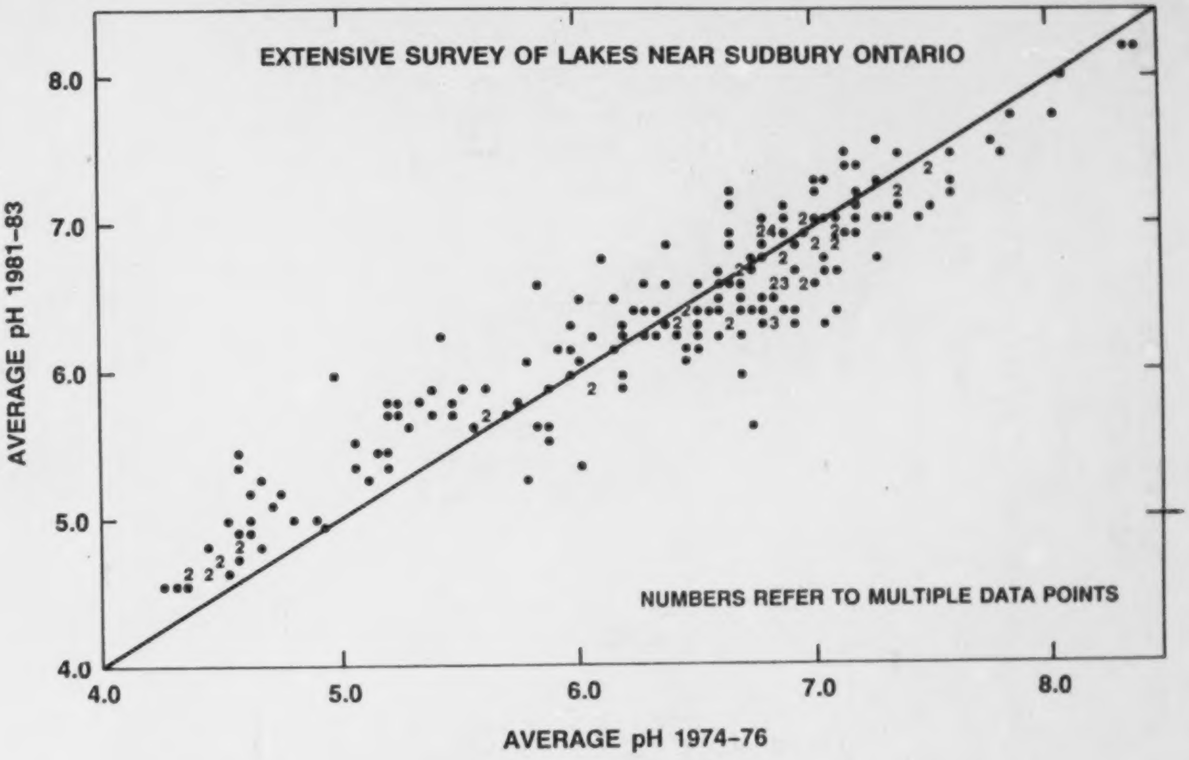


FIGURE 18 -- Changes in the distribution of average pH of lakes in the Sudbury area between the periods 1974-1976 and 1981-1983. All of the lakes which had a pH less than 5.8 in 1974-1976 had a higher pH value in 1981-1983. The increases were up to 1 pH unit (ie. a 90% decrease in acid concentration).

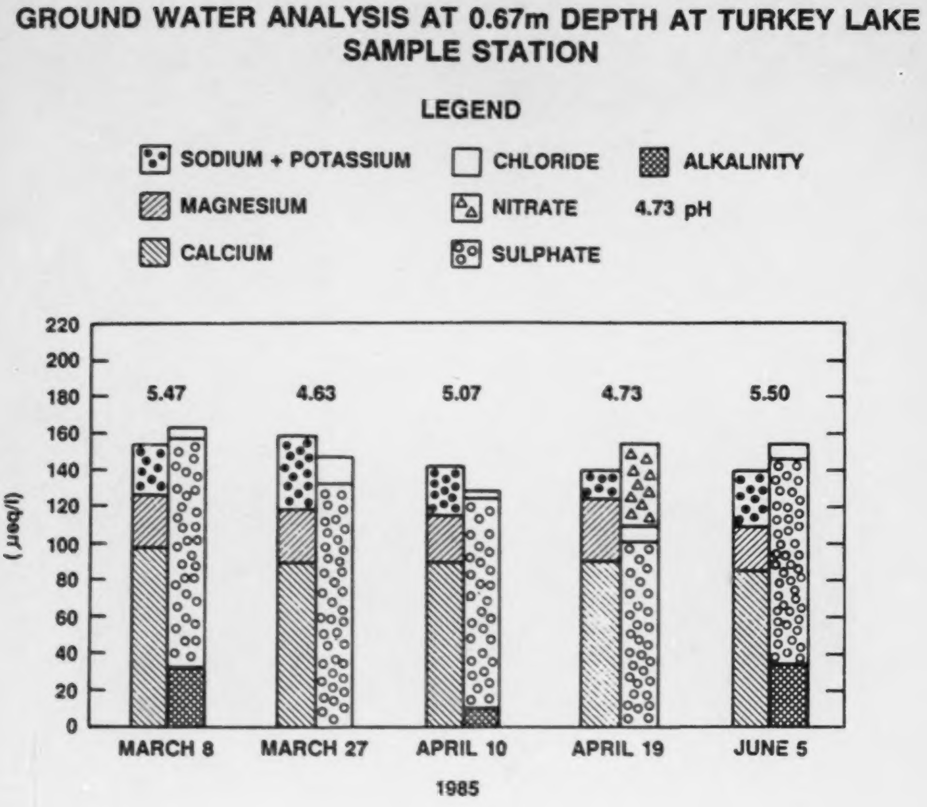


FIGURE 19 -- The chemical composition of soil water during periods of heavy rain (March) and spring runoff (mid-April) for a watershed near Sault Ste. Marie, Ontario. Sulphate is the dominant anion and during heavy spring rains and spring runoff, the alkalinity is exhausted.

February 25, 1987

3.6 TERRESTRIAL EFFECTS

3.6.1 Crops

Visible injury symptoms have not been observed from ambient acidic rain exposures and it is believed that repeated rainfalls with pH less than 3 would be required to cause crop damage (RMCC, 1986). The dose-response data that exist for acidic rain impacts on crops in the U.S. generally demonstrate no significant response differences in the ambient pH range (5.0-4.0).

However, preliminary experiments (Irving, 1986) show an interaction between moisture stress and high levels of acidity in rain (pH = 3.0) (Figure 20) which jointly reduced the yield of one variety of field corn. Other results from the same experiment show that another variety of field corn and two varieties of soybean exhibited no interactive effects of rain acidity and moisture stress on yield. Other studies suggest that pollination is further suppressed by acidic rain in field corn which had reduced pollination due to excessive rainfall which resulted in flooding of the field. Unstressed corn exhibited no effects on pollination from rain acidity.

These results suggest that crops growing under optimal conditions are not affected by rain acidity, but that some crops growing under stress from other factors may be then sensitive to high levels of rain acidity.

In contrast to acidic rain, ozone at ambient levels (.100 ug/m^3 7-hr average during the growing season) reduces the productivity of all agricultural crops tested. This effects essentially all crops in the U.S. and Canada (Heck et.al., 1983) (Figure 21), (Linzon et. al 1984). Crop yield reduction from ambient levels of ozone varies widely by species and cultivar, ranging from 1 percent or less for sorghum and corn, to 20 percent for potato and lettuce to greater than 30 percent for alfalfa, in comparison to yields in charcoal-filtered air.

References:

RMCC (Federal/Provincial Research and Monitoring Coordinating Committee). Aug. 1986. Assessment of the State of Knowledge on the Long Range Transport of Air Pollutants and Acidic Deposition. Part 4. Available from Atmospheric Environment Service, Ontario, Canada.

Irving, P.M. 1986. Report on the Crop Response Workshop of the National Acid Precipitation Assessment Program. April 17-18, Chicago. Available from NAPAP, 722 Jackson Place, Washington, DC 20503.

Heck, W.W., R.M. Adams, W.W. Cure, A.S. Heagle, H.E. Heggestad, R.J. Kohut, L.W. Kress, J.O. Rawlings and O.C. Taylor. 1983. A reassessment of crop loss from ozone. Environ. Science Tech. 12:573-58).

Linzon, S.N., R.G. Pearson, J.A. Donnan and F.N. Durham. 1984. Ozone effects on crops in Ontario and related monetary values. Report No. ARB-13-84-Phyto, Ontario Ministry of the Environment, Toronto.

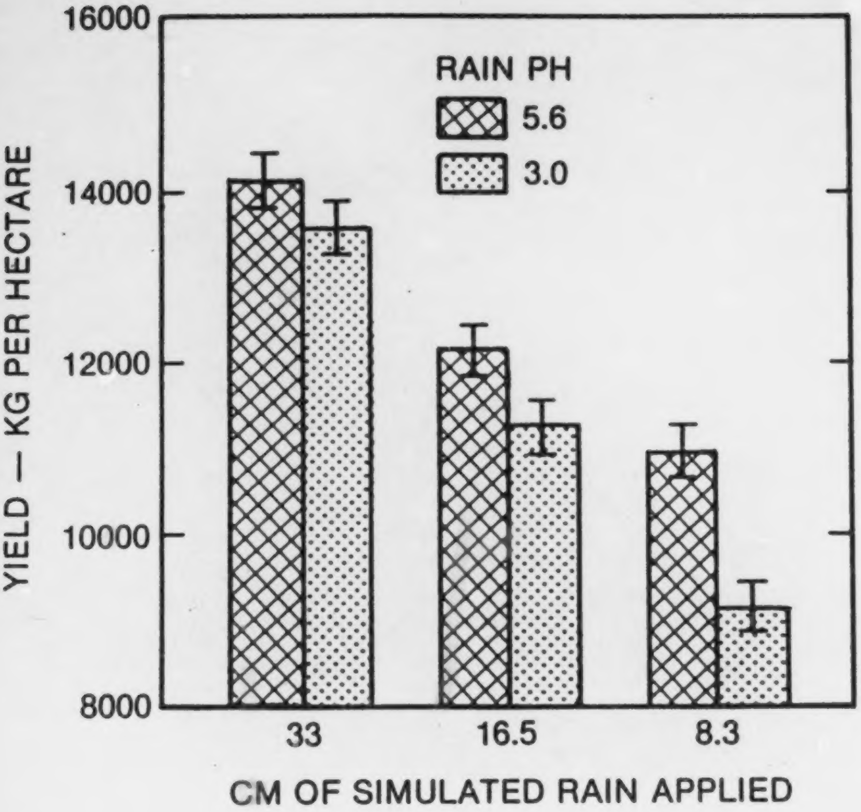


Figure 20: Normal (average rainfall amount during the growing season is 33 cm. Data are expressed as means ± standard error.

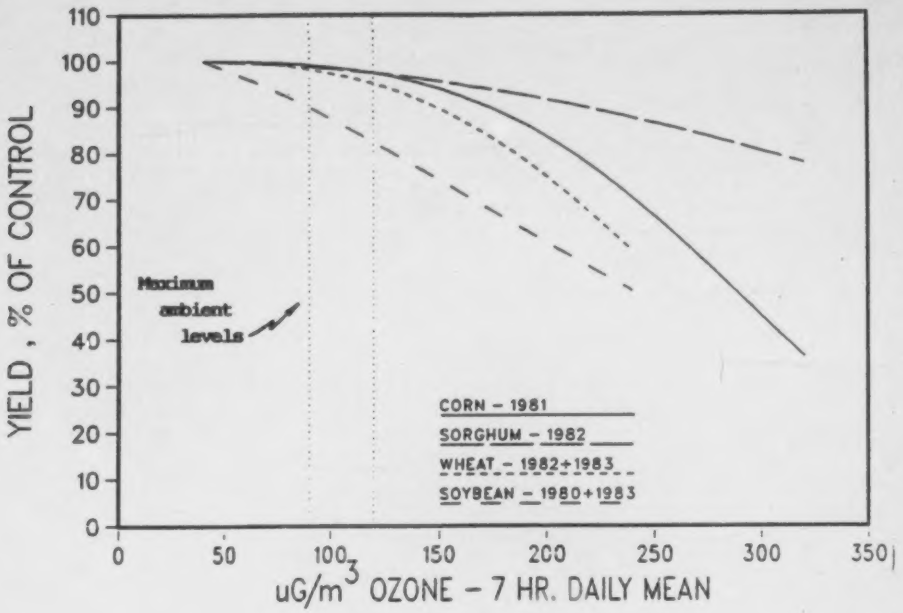


Figure 21: Dose response functions for corn, sorghum, wheat, and soybean exposed to ozone in field studies.

February 25, 1987

3.6.2 Forests

3.6.2.1 Research on Forest Processes

Controlled experiments with seedlings show results for trees that are analogous to those for agricultural crops i.e., no foliar effect from ambient rain i.e., pH 5.0 - 4.0, but measurable growth reductions from ambient levels of ozone i.e., 70 - 140 ug/m^3. These experiments are the first of many which will more definitively examine this pattern and extend it to other conditions including mixtures of pollutants.

3.6.2.1.1 Effects of Acid Precipitation on Seedlings

Three Season Growing Study:

Experiments of simulated rain on seedlings indicate, as in agriculture, no foliar effect until the pH is < 3.0 (average seasonal ambient for the eastern U.S. is pH 4.1-4.9). Seedlings of three tree species (tulip poplar, white oak, and Virginia Pine) were grown for three growing seasons in outdoor forest microcosms near Muscle Shoals, Tennessee. Microcosm boxes were filled with a low fertility, low-base saturation soil (and hence sensitive to acidic precipitation) and were exposed to simulated rain over the ambient range of pH (5.7, 4.5, 4.0, 3.5). The seedlings showed no significant response in growth, photosynthesis, stomatal density, bud break, leaf senescence, respiration or transpiration, cuticle density or microscopic appearance, or chemical composition of fall-collected seedling leaf and needle samples. Thus, tree leaf and needle impacts from ambient acid precipitation appear to be not statistically significant for these species under these conditions.

Reference:

Kelly, J.M, R.C. Strickland, F.P. Weatherford, and J.C. Noggle. 1984. Evaluation of Simulated Acid Precipitation Effects on Forest Microcosms. EA-3500 Electric Research Power Institute.

First Five Week Germination Study:

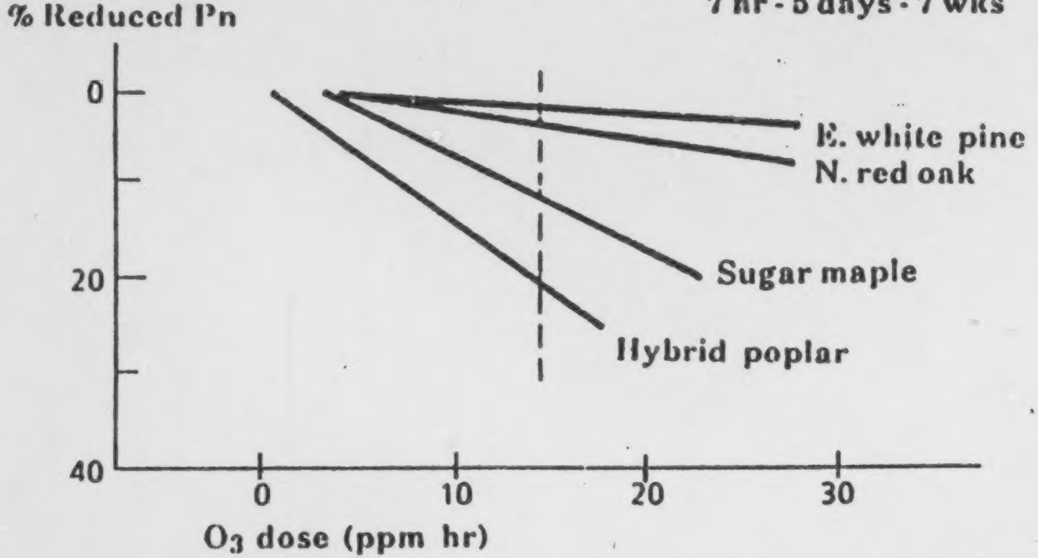
A five week study was conducted. The author concluded, "Acid rain-induced direct injury to forest tree seedlings was investigated in specially designed controlled-environment simulated-rainfall chambers. Seed germinative capacity, seedling survival, seedling growth, and morphological responses to simulated rains of pH 5.6, 4.6, 3.6 and 2.6 were examined during the first growth cycle in 11 commercially important north temperate tree species. Germinative capacity was weakly responsive to rain pH, while seedling survival was more sensitive. No evidence of macroscopic foliar injury was observed at rain pH > 2.6. Treatment with pH ≤ 4.6 rain was sufficient to induce statistically significant growth reductions and morphological changes in coniferous seedlings. Response varied with species, treatment pH and parameter measured. No consistent growth stimulations were observed. Initiation of primary needles, auxiliary meristems and shoot apex height were most affected by simulated pH. Deciduous species were considerably more resistant than coniferous species. Treatment with rain of pH 2.6 was generally required to induce significant growth reductions in deciduous seedlings."

FIGURE 22

Acid Precipitation/Forest Effects

BOYCE THOMPSON RESULTS

Ozone on seedlings — treatments: 20 to 140 ppb
7 hr - 5 days - 7 wks



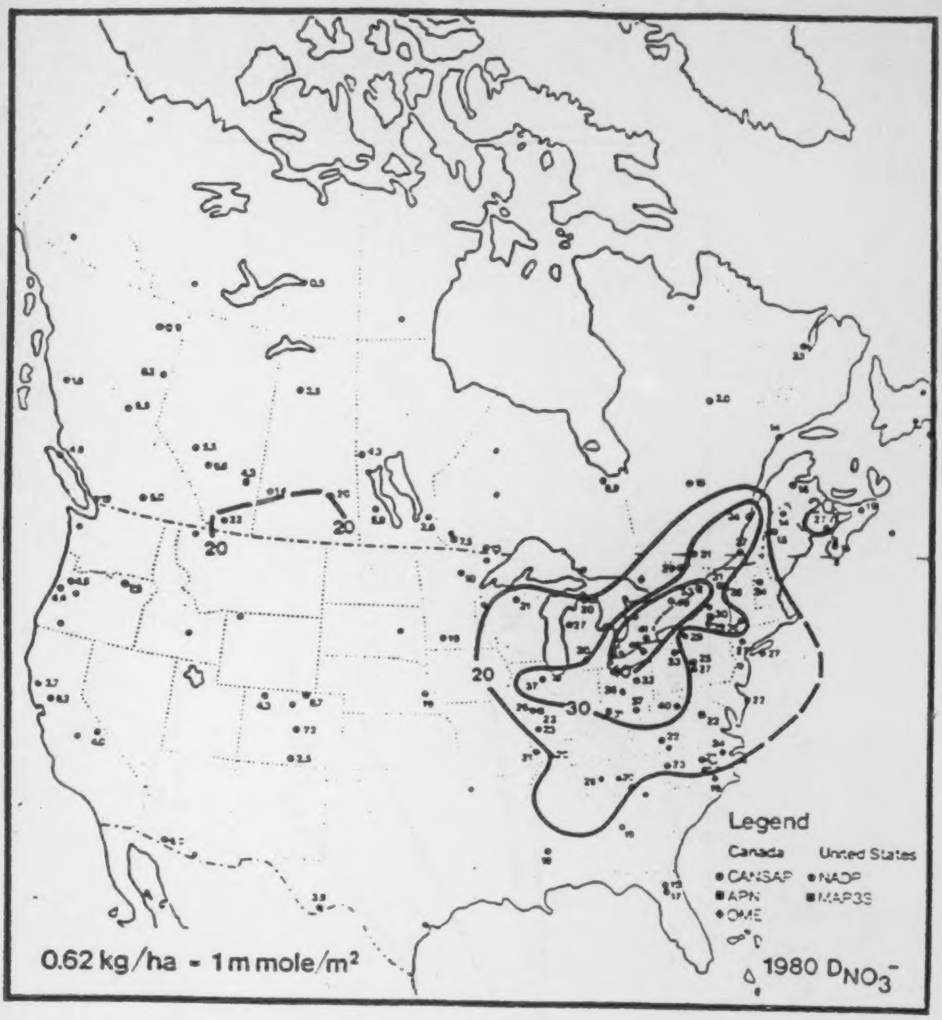
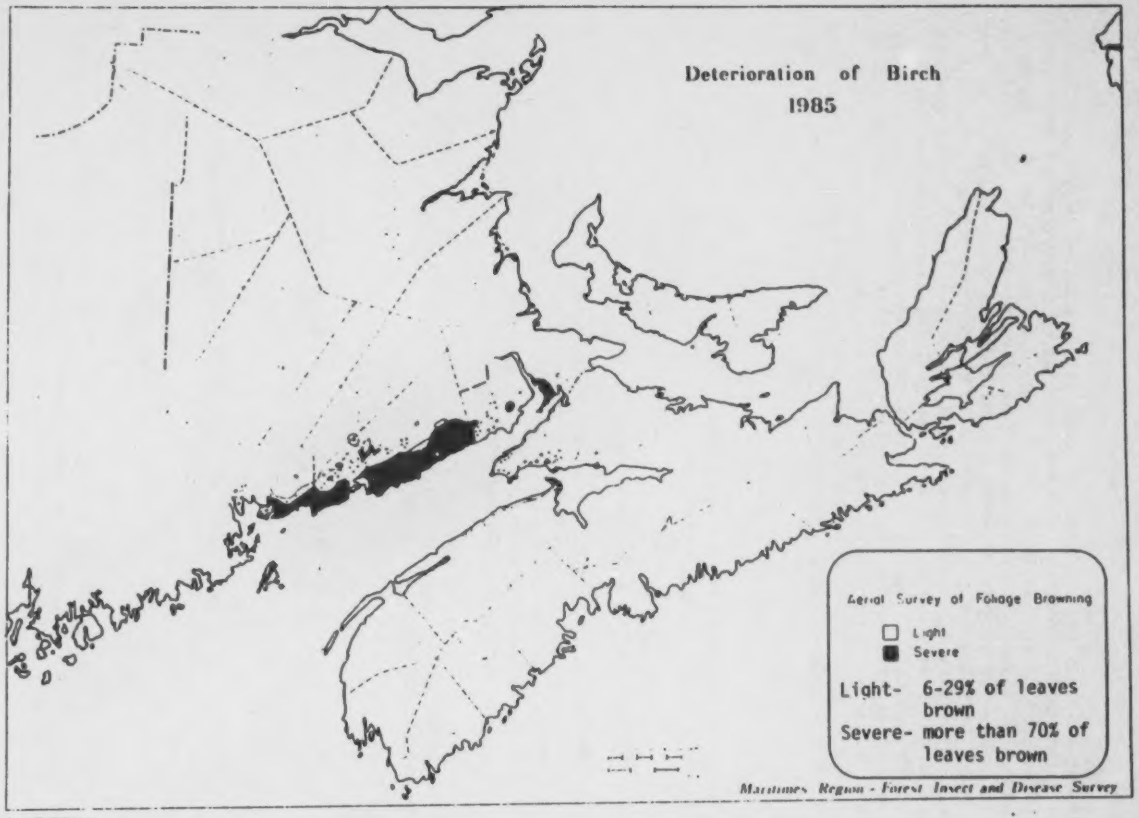

0.62 kg/ha = 1 m mole/m²
Legend
Canada
United States
● CANSAP
■ APN
● OME
● NADP
■ MAP3S
1980 $D_{NO_3^-}$
20
20
20
30
40

FIGURE 23 -- Nitrate deposition in precipitation for 1980.


Deterioration of Birch
1985
Aerial Survey of Foliage Browning
☐ Light
■ Severe
Light- 6-29% of leaves brown
Severe- more than 70% of leaves brown

Maritimes Region - Forest Insect and Disease Survey

FIGURE 24 -- Map of birch decline in 1985.

U.S. Interpretation of the results: Studies were conducted on the germination capacity, growth and morphology of eleven species of deciduous and coniferous trees exposed to simulated rain of pH 5.6, 4.6, 3.6, and 2.6 for five weeks after sowing. No significant effects on cumulative germination, survival, and top growth (i.e., dry weights of above ground biomass) for all species or leaf morphology on three deciduous species were observed at or above a pH of 3.6. In a few species, several other parameters, i.e. hypocotyl length (five species), cotyledon length (five species), primary needle initiation (five species), primary needle length (six species), initiation of auxiliary meristems (three species) and shoot apex height (five species) show higher or lower results at pH 3.6 vs. 5.6 but generally no trends considering the results at pH 4.6. Simulated rain at an acidity of pH 2.6 (about 100 times the average ambient in the eastern U.S.) induced readily measurable impairment of growth in all eleven species.

Reference:

Percy, Kevin. 1986. The effects of simulated acid rain on germinative capacity, growth and morphology of forest tree seedlings. New Phytol. 104:473-484.

3.6.2.1.2 Effects of Ozone on Seedlings

Seedlings of four tree species (hybrid poplar, sugar maple, northern red oak, and eastern white pine) common in northeastern U.S. were exposed to a range of ozone levels up to 280 ug/m^3 over the growing season. This resulted (Figure 22) in reductions in net photosynthesis of 10 to 40 percent over growth under an assumed background level of about 50 ug/m^3.

This is equal to about a 2 percent per year increase in growth per 20 ug/m^3 reduction in average 7-hr. ozone concentration which is about 90 ug/m^3 during the growing season for the eastern U.S.

Reference:

Reich, P.B. and R.G. Amundson. 1985. Ambient levels of ozone reduce net photosynthesis in tree and crop species. Science. 230:566-570.

3.6.2.2 Forest Surveys

Forest surveys can be used to identify hypotheses but alone cannot be used to determine the processes affecting the status of the forests. Specifically, the patterns identified by these surveys cannot be used to draw conclusions about whether acid deposition or other components of air pollution play a role in forest decline.

A wide range of factors may be contributing to the declines currently being observed, including climatic stress, insects, diseases, and acidic pollution. At this time, the specific influence of any given factor is not known.

3.6.2.2.1 Sugar Maple Decline

There is a major sugar maple dieback (See definition in Table 12) in Quebec and to a lesser extent in Ontario. Surveys have been carried out in Quebec and it is noted that "there were very few cases of maple stands totally exempt of damage in some form or another". The results of the 1985 survey are

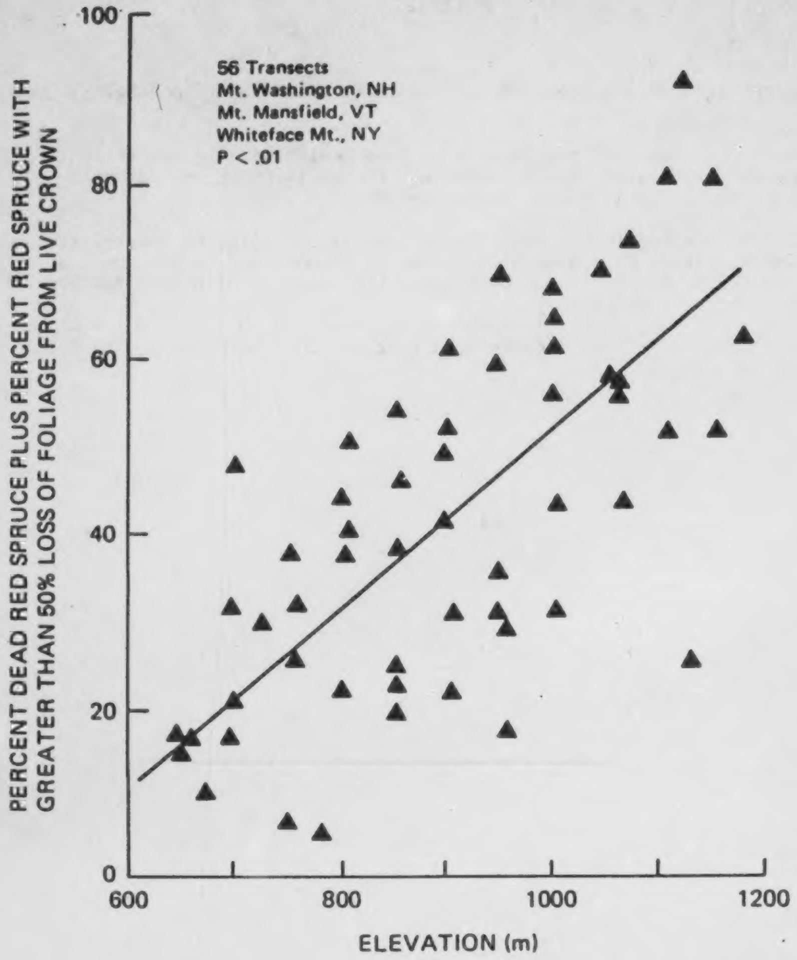


Figure 25: Populations of severely declining (>50 percent foliar loss from the live crown) and dead red spruce at systematically sampled sites in the northern Appalachian Mountains. Only trees of >10-cm dbh (diameter at breast height) reaching into the canopy were rated. Adapted from NAS Report: Acid Deposition, Long Term Trends, p. 211.

TABLE 11

Several terms often used to describe injury to forests are defined below:

Tree disease — a sustained disturbance to tree health usually adversely impacting physiological processes, sometimes ending in death and normally having a single abiotic or biotic causal factor.

Forest decline — a complex disease of a forest often including several tree species, characterized by a general decrease in stand vigor, sometimes leading to increased mortality and caused by a number of abiotic and biotic factors working together or sequentially.

Dieback — a symptom of tree disease or forest decline characterized by dying of shoots from the tip back.

TABLE 12

AREA (ha) OF SUGAR MAPLE STANDS AFFECTED BY DIEBACKIN THE TERRITORY COVERED BY THE 1985 AERIAL SURVEY

ADMINISTRATIVE REGION	ADMINISTRATIVE UNIT	Healthy or Trace (0-10%)		Light (11 - 25%)		Moderate (26 - 50%)		High (51% +)		TOTAL	
		Thousands of (ha)	(%)	Thousands of (ha)	(%)	Thousands of (ha)	(%)	Thousands of (ha)	(%)	Thousands of (ha)	(%)
Bas St-Laurent Gaspesie	11	0.7	88	0.1	12	-	-	-	-	6.8	100
Quebec	34	39.5	28	84.0	60	12.9	9	2.2	2	138.5	100
Quebec	35	50.0	72	18.3	26	1.0	1	0.04	0	69.3	100
Trois-Rivieres	41	6.0	36	8.0	48	2.0	13	0.3	2	16.3	100
Estrie	51	155.7	68	66.0	29	5.0	3	1.6	1	228.7	100
Montreal	63	65.8	82	12.6	15	1.3	3	0.4	1	80.1	100
Total (ha) (%)		316.6	60	178.2	35	22.3	3	4.6	1	533.6	100

Healthy:	100% of crown foliage present. No abnormal coloring of leaves.
Trace:	1-10% of crown foliage missing. Leaves are generally smaller and yellowish.
Light:	11-25% of crown foliage missing. Presence of small dead branches.
Moderate:	25-50% of crown foliage missing. Presence of dead branches and peeling of bark on the main branches and trunk.
High:	51% and over of crown foliage missing. Presence of dead branches and peeling of bark on the main branches and trunk.

Table revised from Bordeleau, Clement. 1986. "Sugar Maple Dieback: Extent of Damage in the Appalachians." Maple Producers Information Session. Page 27.

presented in Table 11. Some damage was observed in 40% of the 533,582 hectares surveyed. The Quebec surveys indicate that dieback of sugar maple occurs throughout its range and within different forest types and on several different sites. (See Figure 2 for sulfur deposition in 1980 and Figure 24 for nitrate deposition in 1980).

Reference:

Clement Bordeleau in Report on the Maple Producers Information Session, May 8, 1986, Quebec City, Quebec, Gouvernement du Quebec, Ministere de l'Agriculture Pecheries et de l'Alimentation.)

Gagon, G., L. Robitaille, G. Roy et C. Gravel. Dieback in maple stands - the behaviour of some ecological variables. Presented at the NATO Advanced Research Workshop on Effects of Acidic Deposition and Air Pollutants in Forests, Wetlands and Agricultural Ecosystems, Toronto, Canada. pp. 1.

3.6.2.2.2 Birch Decline

Other species that have shown decline symptoms, based on general surveys, include beech, red maple, and yellow birch. (Gagnon, G.L. et al. op. cit., 1985. Birch decline has been documented in parts of southern New Brunswick and parts of Nova Scotia bordering on the Bay of Fundy, the area affected in 1985 is shown in Figure 24. (Canadian Forest Insect & Disease Survey Report, 1985).

3.6.2.2.3 Red Spruce Decline

Surveys of red spruce in New England spruce-fir forests are beginning to quantify the status of those forests (see for example Figure 25). They have shown that:

1. Across the range of the spruce-fir type (stands vary from 1 to about 8 species) in New Hampshire, New York, and Vermont (excluding areas with recent spruce budworm outbreaks), 23% of the 1.3 million acres surveyed were rated as having heavy mortality (i.e., of all species); on these acres, 12 to 26% of the red spruce component (live plus standing dead) had died within approximately the last 5 years.

2. High elevation stands (above 2800 ft or 850m) have had decreased basal area growth (as compared to earlier periods), foliar damage and high mortality rates; lower elevation stands also display decreased growth, but no foliar damage or abnormal mortality rates, and;

3. Mortality and loss of foliage increases with elevation in 56 transects taken in NH, NY, and VT (See Figure 25).

The Academy study concluded, "The abrupt and synchronous changes in ring width and wood density across such a wide area seem more likely to be related to climate than to air pollution. Acid deposition or other airborne chemicals might play a role in predisposing the trees to the factors that are injurious...."

GEORGIA PIEDMONT & MOUNTAINS

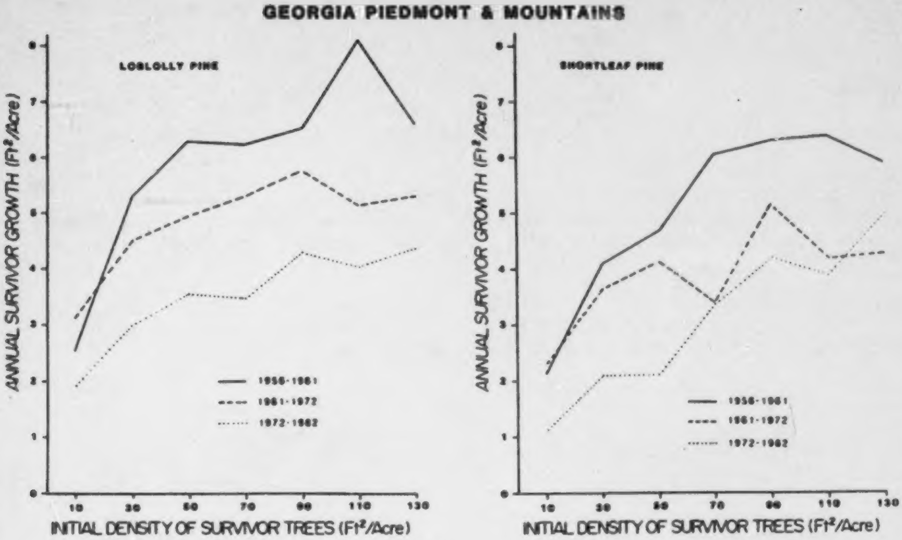


Figure 26: Net annual basal area growth plotted against stand density of two commercial pine species as surveyed in the 1950s, 60s, and 70s. In most cases, growth declines over time.

References:

Hornbeck, J.W. and R.B. Smith. 1985. Documentation of red spruce decline. Can. J. For. Res. 15:1199-1201.

Johnson, A.H. and S.B. McLaughlin. 1986. The nature and timing of the deterioration of red spruce in the northern Appalachian Mountains. 200-230 pp. in: Acid Deposition, Long Term Trends. National Academy Press, Washington, D.C. 506 pp.

Weiss, M.J., L.R. McCreery, I. Millers, M. Miller-Weeks, and J.T. O'Brien. 1985. Red Spruce and balsam fir decline and mortality in NY, VT, and NH, 1984. USDA Forest Service NE Area. Report NA-TP-11. 53 pp.

3.6.2.2.4 Growth Reductions in Conifers

Surveys of natural stands of loblolly and shortleaf pine in the Piedmont and Mountain regions of Georgia showed that net annual basal area growth of surviving trees was smaller during more recent surveys than during previous surveys. (See Figure 26 which shows survey dates and changes in growth.) Surveys in Virginia, North and South Carolina show similar trends. Visible symptoms of forest stress are not apparent.

Reference:

Sheffield, R.M., N.D. Cost, W.A. Bechtold and J.P. McClure. 1985. Pine growth reductions in the Southeast. Resources Bulletin SE-83. USDA Forest Service, SE Forest Experiment Station, Asheville, NC. 112 pp.

3.7 MATERIALS

Observed corrosion and deterioration of materials in the structural environment, including structures important to our cultural heritage, which as such should be preserved, can in part be attributed to acidic deposition. The primary effect of acidic deposition is to accelerate naturally occuring decay processes. Although the acceleration cannot be quantified at this time, nor can the mechanisms of the interaction between material surfaces and deposition be described completely, it is understood that surface moisture plays a significant role in both deposition and corrosion/alteration processes.

While the overall ability to define the principal causes of material deterioration and the processes is extremely limited, new findings include:

- Formation of crusts and black deposits is one evidence of pollution interaction with stone. Analyses of these surface deposits confirm that SO_4 is the chief constituent and only trace amounts of NO_x are found in the crust. (Livingston, R.A. 1985). Development of crusts that can exfoliate appears to be greatest on areas of structures that are exposed to SO_2 pollution without being washed by rainwater (Fassina, 1985).

- Corrosion films formed on metals and metal-coated steel products exposed by the Bureau of Mines at field sites in the eastern United States for times U.S. from 1 to 36 months had: 1) chemistries that were independent of environment in short-term exposures; 2) morphologies that were, in some cases, highly altered by solution processes; and 3) runoff losses for zinc that were dependent upon hydrogen ion loading (Flinn et.al., 1986).

- Initial results from exposure testing of limestone and marble indicate that dissolution of carbonate rock surfaces is linearly related to hydrogen ion loading. (Reddy, M.M., Sherwood, S.I., Doe, B.R., 1986).

References:

Livingston, R.A. 1985. The Nanto stone deterioration and restoration of Loggia Cornaro in Padova. Proc. Vth Int. Congress on Deterioration and Conservation of Stone. Presses Polytechniques Romandes. Vol. 1, pp. 313-324.

Fassina, V. 1985. The Nanto stone deterioration and restoration of Loggia Cornaro in Padova. Proc. Vth Int. Congress on Deterioration and Conservation of Stone. Presses Polytechniques Romandes. Vol. 1, pp. 509-516.

Flinn, D.R., S.D. Cramer, J.P. Carter, D.. Hurwitz, and P.S. Linstrom. 1986. Environmental Effects on Metallic Corrosion Products Formed in Short-Term Atmospheric Exposures. ACS Symposium Series 318, Materials degradation caused by acid rain. American Chemical Society, Washington, D.C. pp. 119-151.

Reddy, M.M., S.I. Sherwood, and B.R. Doe. 1986. Limestone and Marble Dissolution by Acid Rain: An Onsite Weathering Experiment. ACS Symposium Series 318, Materials degradation caused by acid rain. American Chemical Society, Washington, D.C. pp. 226-238.

US/CAN Submission Disk
DOC 2

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 2: Do you believe that S. 879 is appropriate legislation for promoting the widespread use of various clean coal technologies?

- Specifically, how would S. 879 contribute to U.S. energy policy goals?

Answer: S. 879 shares the Administration's goal of advancing the demonstration and deployment of clean coal technologies that hold the potential to accelerate the availability of the innovative technologies, and, as such, offers a basis for working towards a bipartisan Clean Coal Technology authorization bill.

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 3: Critics have argued that additional research on clean coal technologies is not necessary and that clean coal technologies are sufficiently mature for commercialization.

- Please comment on the maturity of various clean coal technologies.
- When will they be available for deployment?
- Please describe those factors which present the most significant technological risks to widespread deployment of clean coal technologies and would require additional research before commercialization would occur. Please provide information on at least the following technologies: advanced physical coal cleaning; furnace injection; duct injection; limestone injection multistage burner; integrated gasification combined-cycle; advanced flue gas desulfurization; gas reburning; atmospheric fluidized bed combustion; and pressurized fluidized bed combustion.

Answer: Individual projects using specific coal technologies are being awarded contracts under the first solicitation for the Clean Coal Technology Projects or may be the subject of subsequent proposed rounds in the Program. The Clean Coal Technology I projects are believed to be sufficiently developed and ready for a large demonstration as the next logical step in achieving commercial acceptance. However, other clean coal technologies and applications that are the subject of our core research and development programs are not sufficiently advanced to be demonstrated without undue technical and economic risk. It is, therefore, of utmost importance that this research and development activity on clean coal technologies outside of those in the Clean Coal Program be continued in order to logically bring them to an appropriate point of readiness for large commercial demonstration.

The maturities, estimated times of availability for deployment, and factors that affect technological risk, and, therefore, which may inhibit widespread commercial deployment in the absence of further research, are discussed, by technology, below:

A. Coal Preparation

A number of physical approaches to coal preparation are already commercially practiced. These techniques are based on physical separation of the impurities from coal based on differences in the specific gravity and mass of the coal constituents. Existing commercial practice typically removes about 30 percent of the ash and sulfur prior to combustion. For certain coals, as much as 50 percent of the sulfur is removed.

Advanced physical coal cleaning technology is under development and incremental improvements will be available commercially during the next five years. The exact timing will depend, first, on the success of ongoing studies in process development and demonstration and, second, upon the existence of a market that will support commercialization.

The advanced techniques under development are based on the fact that more of the pyrites, which contain sulfur, are released from coal as the raw coal is ground to smaller particle sizes. However, physically separating particles smaller than 200 mesh is difficult. As a result, research is concentrating on techniques to efficiently grind the coal and also to recover clean coal particles and reject the mineral particles. One approach involves agglomeration of the coal in the presence of an organic liquid. Agglomeration techniques capable of removing 90 percent of the ash and pyritic sulfur from selected coals have been developed to a pilot scale capable of producing a few tons per day.

For broader commercial use on a variety of U.S. coals, technical uncertainties in a number of techniques need to be resolved. These various techniques will attempt to exploit differences in surface properties and specific gravities of very small coal and mineral particles.

In addition to agglomeration, cyclones can be used to improve gravity separation, froth flotation is possible with microbubbles, and electrostatic techniques can be used on dry coal to produce a dry product. All of these potentially valuable techniques require significant additional research.

B. Furnace Sorbent Injection/Limestone Injection Multistage Burner (LIMB)

This technology has been demonstrated overseas with mixed results. Short-term tests were successfully completed in the

U.S. with a 50 MW lignite-fired utility boiler. Full scale demonstrations are proceeding in the U.S. as follows:

- o EPA/B&W wall-fired demo at Lorain, Ohio, with a subsequent extension under the Clean Coal Technology Program.

- o EER wall-fired and tangentially-fired demos under the CCT Program.

- o EPA/EPRI prototype tangentially-fired demo (Richmond Power and Light).

- o EPA/DOE full scale tangentially-fired demo at Yorktown, Virginia (contract negotiation now underway)

- o The primary risks with furnace injection of sulfur-absorbing reagents are boiler slagging and fouling which have the potential to reduce steam production and cause boiler derating as well as increase maintenance requirements. Boiler tube erosion and corrosion are also potential problem areas. The increased particulate loading may result in non-compliance with particulate emission standards and the waste material may contain some unreacted lime which could present waste handling/management problems.

- The risks for LIMB are the same as for furnace injection with one addition: the use of low NO_x burners can create reducing zones within the furnace that can cause corrosion.

- Based on current activities, it is estimated that this technology will be available for widescale commercial deployment in the early 1990's.

C. Duct Injection

Development efforts are currently underway both at the proof of concept scale (5-12 MWe boiler slipstream) under the DOE/CCT program and at full scale in the EER cyclone-fired boiler and the Coolside demonstration in conjunction with the B&W LIMB project. If these efforts prove successful, this technology should be available for commercial deployment in the latter part of CY 1991.

The primary risk in the use of this technology is the potential for failure to achieve the desired SO_2 reduction levels. This can occur when insufficient water is vaporized by the flue gas. As a result, this gas is not cooled down to the temperature regime required for good SO_2 removal. Deposition of the sorbent occurs on the wetted wall where it no longer presents sufficient surface area for good reaction with the SO_2.

Meeting particulate emission requirements is another potential problem area, and waste handling/management may also require special consideration since appreciable quantities of slaked lime will be present, and, depending upon the specific process considered, sodium hydroxide and sodium salts as well may be present in the waste.

D. Advanced Flue Gas Desulfurization Processes

Maturity varies, depending upon the particular process under consideration, and ranges from laboratory and bench scale investigations through proof of concept (5-10 MWe) and, in the case of some advanced lime/limestone systems, up to full scale demonstrations. The timeframe expected for deployment is estimated to be 1993-2000 depending on the state and maturity of the various processes.

Technological risks involved in commercialization will vary depending on the particular system under consideration. One area of risk, common to most of the processes in this category, are those associated with scaleup.

E. Gas Reburning

Gas reburning is a unique method of converting NO_x mainly to nitrogen. Early research has demonstrated that significant flue gas NO_x reductions can be achieved, based upon the principle that carbon-hydrogen fragments of larger organic fuel molecules react with NO_x. When this happens, NO_x is mainly converted to molecular nitrogen and the carbon-hydrogen fragments are oxidized to carbon monoxide and water. This concept has recently been applied at a foreign installation, but it has not been demonstrated commercially in the United States. Extensive U.S. bench and pilot scale testing has been completed to characterize the fundamental processes and develop a scaleup methodology. Completion of the reburning project in the Clean Coal Technology Program should make this process commercially available by the mid 1990's (i.e., 1990-1995).

The primary risk inhibiting the development of the technology for commercial deployment is the as yet unresolved question of identification of those process parameters that will reduce NO_x formation, while minimizing the undesirable side effects normally associated with NO_x avoidance practices. These side effects can include a combination of high emission of carbon monoxide, soot, and partially oxidized organic compounds, together with lower boiler efficiency.

F. Atmospheric Fluidized Bed (AFB).

AFB technology is now commercially available for large industrial boiler applications (200,000 lb/hr steam and greater). Commercial units are offered by 19 U.S. boiler manufacturers and approximately 115 units are either operating or committed to construction.

AFB technology has advanced to the demonstration stage for utility application and several utilities are seriously considering AFB for electric power generation.

The technical, reliability-related, environmental and economic factors that must be known before a utility or an industrial company with light or small application potential can assess the business risk is associated with purchasing and installing commercial AFB units remain to be demonstrated.

Nonetheless, it is expected that the AFB technology for utility application, as well as for smaller industrial systems, will reach commercial status by the early 1990's.

G. Pressurized Fluidized Bed (PFB).

PFB technology has progressed to the point where sufficient data are available to design and construct a prototype PFB coal-fired demonstration plant. The American Electric Power Service Corporation was selected to construct and operate a 70 MWe PFB combined-cycle demonstration plant at the TIDD Power Station under round 1 of the Clean Coal Technology Program. The project schedule calls for commissioning this plant by 1990, followed by two years demonstration (operations) in a utility power-generation environment. However, the technical, reliability-related, environmental, and economic factors that must be known before a utility can assess the business risks associated with purchasing and installing commercial PFB units await demonstration at this time.

On this basis, it is considered that PFB technology will not be deployed commercially until the mid 1990's. It should be noted that the core R&D program on PFB is directed toward the development of 2nd generation PFB systems which will show significant improvements in the economics, plant efficiency/reliability, and environmental aspects of this technology.

H. Integrated Gasification Combined Cycle

The first commercial scale integrated gasification combined cycle (IGCC) unit is the Coolwater Coal Gasification Demonstration Plant. This 100 MW plant was built at Southern California Edison's Coolwater Station, near Daggett, California. The plant operates at an efficiency of approximately 29 percent limited by the lack of availability of high-temperature, high-efficiency turbines and suitable high temperature cleanup systems. Higher temperature turbines are now under development in the U.S. and Japan and could be available for deployment in the early 1990's. High temperature cleanup systems are much less mature and will likely not be sufficiently developed for commercialization prior to the middle 1990's. DOE's first CCT selections included three projects employing different types of hot gas clean-up.

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 4: How many demonstration projects for each type of technology are necessary to convince potential users--utilities and industries--that the technologies are both cost-effective and reliable? How large should these demonstration projects be?

Answer: Some technologies need to be demonstrated on a variety of boiler types; some on a variety of coals; some have very significant differences in configuration and, therefore, need demos for each type. In general, one demonstration project for each specific type of technology should be sufficient to convince potential users--utilities and industries--that the technologies are both cost-effective and reliable. The demonstration project does not need to be a complete, full-scale commercial plant (first-of-a-kind), but may, for example, represent a single train in a multi-train plant, or may be of less than commercial scale. It should be representative of the application being considered for the technology. However, the demonstration must be of sufficient scale to provide the technical, environmental, economic data and operating experience necessary to define the commercial configuration.

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 5: Do the regulatory incentives in the Byrd bill, either together or individually, provide incentives for increased deployment of clean coal technologies?

- What other incentives would provide for the increased deployment of these technologies?
- When will the report of the Special Task Force on Regulatory Relief be complete?

Answer: Regulatory incentives and disincentives at Federal, state and local levels for increased deployment of clean coal technologies are currently under review by the Presidential Task Force on Regulatory Relief. In March, the President asked the Vice President, who chairs the Task Force, to conduct an assessment of these and associated issues to identify opportunities for addressing them under existing laws. The findings and results of the Task Force review are expected to be completed this fall, including recommendations for changes to existing regulations.

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 6: How can we better coordinate the timing of a demonstration and deployment Program to get the most benefits from these technologies?

Answer: The timing of the program can be optimized by concentrating on the near term demonstration of these new technologies with a view to deployment during the "window" of opportunity that will open for these systems in the mid 1990's. By the middle of the next decade, utilities will be increasingly confronted with the two-fold problem of an aging boiler population and the need for increasing their power generating capacity. More than half of all coal-fired boilers will be 25 years old or older by the mid 1990's. In the eastern United States alone, there are 410 units of coal-fired utility capacity of 100 megawatts or larger that were placed in service from 1955 to 1975 and which do not have post-combustion SO_2 control devices. Utility decision makers will soon have to make some fundamental choices about many of these units -- including whether to retire or refurbish them.

At the same time, the demand for electricity is expected to be growing while reserve margins are expected to be declining. Estimates for increasing power demand vary, typically, between two and three percent per year. Even with the more conservative two-percent growth rate, the United States could require as much as 100,000 megawatts of additional capacity by the end of the next decade.

If these advanced technologies are successfully demonstrated at commercial scale between now and the early 1990's, utilities may use them to resolve the two-fold problem of modernizing aging plants and meeting increased power demand.

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 7: Please describe the environmental benefits derived from the use of the clean coal technologies?

- How do they compare to the currently available flue gas desulfurization technologies in terms of environmental performance and cost?
- How do they compare to the use of low sulfur coal in terms of environmental performance and cost?

Answer: Table I compares the performance capabilities and end data of the emerging clean coal technologies with those of the conventional technologies.

The environmental benefits derived from the use of the clean coal technologies differ as between retrofit technologies which can be used on existing plants to reduce emissions, and repowering technologies that replace all or a significant portion of the original plant and often increase capacity while reducing emissions, and technologies applicable to new facilities. Often a technology may satisfy more than one application category.

Retrofit techniques such as advanced coal cleaning, limestone injection multistage burner, slagging combustors/gas reburning, induct sorbent injection, coal-water mixtures and advanced flue gas cleanup, used separately or in combinations, can control either or both SO_2 and NO_x and produce an environmentally safe waste product. Although the sulfur emission reduction potentials of some of these technologies alone may not be as high as conventional flue gas scrubbing, the reduction levels could be sufficient to meet future requirements for existing plants and their greater cost-effectiveness may help reduce costs of meeting such future requirements.

Repowering technologies, such as Integrated Gasification Combined Cycle (IGCC) and Fluidized Bed Combustion (FBC) are able to reduce both SO_2 and NO_x emissions. In the case of IGCC, sulfur emission reductions greater than 99% have been achieved, while pressurized FBC is capable of lowering sulfur emissions by 95%. IGCC and FBC technologies can also reduce NO_x emissions in the range of 85% compared to a conventional coal-fired power plant.

Reducing air emissions using existing techniques of the 1970's and early 1980's would pose severe problems due to limitations of conventional technology. Conventional coal cleaning has only a limited ability to remove sulfur impurities: typically only 10 to 30 percent of the total sulfur in coal. Flue gas scrubbing is very costly and can be applied only to plants that have the available space required to accommodate scrubber operation. In addition, the operation of scrubbers consumes a portion of the power plant's energy output, thereby lowering efficiency, and today's typical system produces massive amounts of waste product that is difficult to handle.

Coal switching may increase fuel costs for some utilities, depending on the coal and transportation premiums that are paid. Coal switching may also be the most economical option for some other utilities. However, other costs must also be considered. Switching to low sulfur coal can result in boiler derating.

TABLE 1
PERFORMANCE OF EMERGING CLEAN COAL TECHNOLOGIES
IN COMPARISON TO CONVENTIONAL TECHNOLOGIES

	Efficiency	Power Output	Plant Life	% SO2 Reduction	NOx Emitted	Incremental Cost of Electricity (mills/kWh) (a)	Capital Cost ($/kW)	SO2 Control Cost ($/ton) (b)	SO2 + NOx Control Cost ($/ton) (c)
Conventional Technology									
Coal Cleaning	Small increase	No change	Slight extension	10-30	No Change	2-3	Additional fuel cost only	350-650	350-650 (d)
Flue Gas Scrubber on New Facility	Decrease	Moderate decrease	No change	90+	No Change	9-10	180-200	336-425	336-425 (d)
Retrofit Flue Gas Scrubber	Decrease	Moderate decrease	No change	80-90	No Change	11-12	250-300	450-502	450-502 (d)
Repowering Technology									
Integrated Gasification Combined Cycle	Moderate increase	50-150% increase	Moderate extension	95-99	Moderate Reduction	1-2	1100-1200	81-278	60-202
Pressurized Fluidized Bed Combustion	Slight increase	40-50% increase	Moderate extension	90-95	Moderate Reduction	4-6	800-900	259-352	205-290
Atmospheric Fluidized Bed Combustion	No change	10-15% increase	Moderate extension	85-90	Moderate Reduction	6-8	700-800	323-447	260-356
Retrofit Technology									
Advanced Flue Gas Cleanup	Decrease	Small decrease	No change	90+	High Reduction	10-12	175-190	350-400	275-300
Limestone Injection Multistage Burner	Decrease	Small decrease	No change	50-60	Moderate Reduction	5-8	80-110	175-300	150-180
Slagging Combustor	Small decrease	Small decrease	Slight extension	50-90	Moderate Reduction	1-2	50-60	50-100	60-95
Gas Reburning	No change	No change	Slight extension	10-20	Moderate Reduction	Depends on gas price	10-20	NA	NA
In-duct Sorbent Injection	Small decrease	Small decrease	No change	50-70	No Change	2-4	60-90	100-200	100-200 (d)
Advanced Coal Cleaning	Small increase	No change	Slight extension	30-90	No Change	6-21	Additional fuel cost only	210-920	210-920 (d)
Coal Slurry	Small decrease	Small decrease	No change	10-90	No Change	11-23	20-50	425-980	425-980 (d)

Notes: (a) Assumes base for retrofit is conventional coal-fired power plant with only particulate removal devices. For repowering, the base is the same conventional coal-fired powerplant plus additional power from greenfield NSPS unit to account for the increase in output due to repowering. For repowering technologies, capital costs are relatively high because the output (i.e., capacity of the plant) is increased. The incremental costs of electricity are those costs associated with reducing emissions from the base plant.

(b) Assumes that the coal contains 3 percent sulfur, that the heat rate for retrofit is 10,000 Btu/kWh, and that the heat rate for repowering is 9,000 Btu/kWh. For devices that control both NOx and SO2, no credit is given for NOx control.

(c) Same assumptions as for (b). Also assumes that a pound of SO2 controlled is equal to a pound of NOx controlled, and assumes that 1.5 lbs of NOx/MMBtu are emitted if there are no controls.

(d) Technology does not control NOx.

QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 8: Please describe the repayment and recoupment provisions for Phase I of the Clean Coal Program. Are the provisions negotiated separately for each project? Generally, how might they work? Is a project sponsor's willingness to repay DOE used as a part of the criteria for selection of the project?

Answer: The provisions for the Recoupment Plan as provided in the Model Cooperative Agreement of the Clean Coal Technology Program Opportunity Notice (February 17, 1986) are as follows:

> It is the policy of Department of Energy (DOE) to recover an amount the Government's contribution to the project. This recovery is derived from at least the following potential revenue sources: (1) Operation of the demonstration project beyond the operating phase of the Cooperative Agreement. The net revenue from the operation (after operating costs) will be shared in proportion to the overall cost-share for the project. (2) The commercial sale, lease, and licensing of the technology demonstrated under the Clean Coal Techonlogy Program.
>
> The Government's right to revenues resulting from the supported work continues until it has recouped all of its expenditure for the project, or until 20 years have elapsed from the end of the project period, whichever comes first.

A recoupment plan was required from successful offerors after selection. The plans are negotiated on a project by project basis. Each of the recoupment plans negotiated to date contain realistic payment recovery plans based on market penetration for the demonstrated technology.

The proposals were evaluated according to the criteria identified in Section V of the PON. Payback was not one of the criteria.

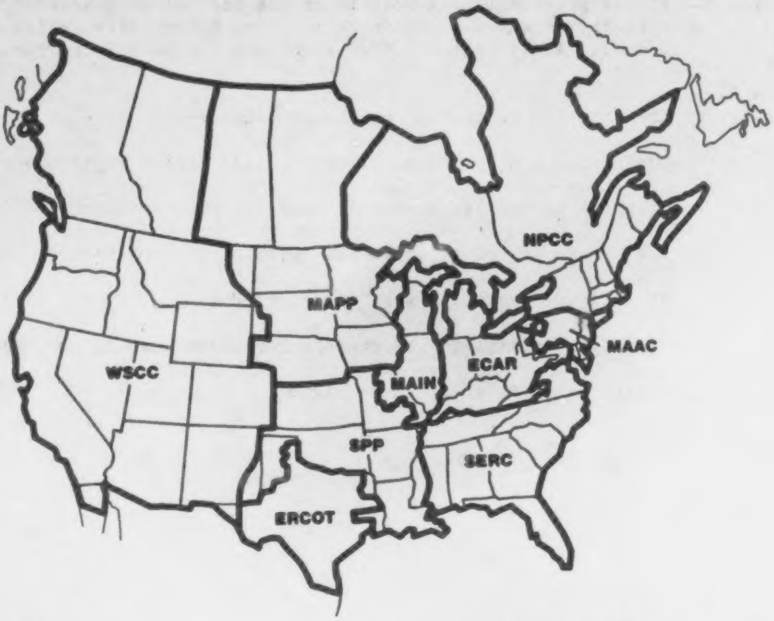
QUESTIONS SUBMITTED BY SENATOR FORD

CLEAN COAL TECHNOLOGY PROGRAM

Question 9: Please provide an age profile of the coal-fired generating capacity of the U.S. by North American Electricity Reliability Council (NERC) region. Please include the median age for each region.

Answer: The attached graphs and tables show the age profile of coal-fired generating capacity for each (NERC) region by number of units as well as amount of capacity gas of the end of 1985. The median age of units is also presented. The data presented is derived from the Power Statistics data base of the Edison Electric Institute. The regions for which data is presented are defined also in an attached Figure.

North American Electric Reliability Council



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 196[illegible] to promote the RELIABILITY of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the power systems in the United States and Canada.

RELIABILITY, in a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Bulk power electric system reliability can be addressed by considering two basic and functional aspects of the bulk power system—adequacy and security.

ADEQUACY is the ability of the bulk power electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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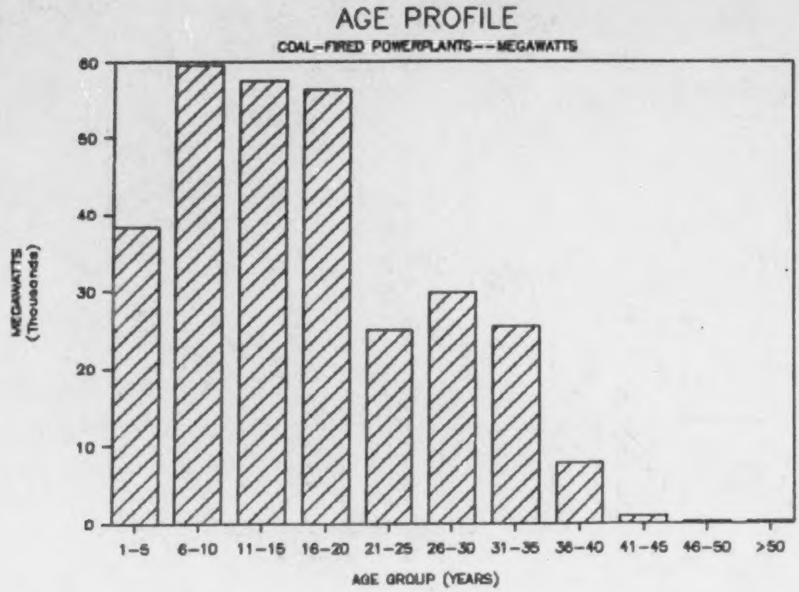
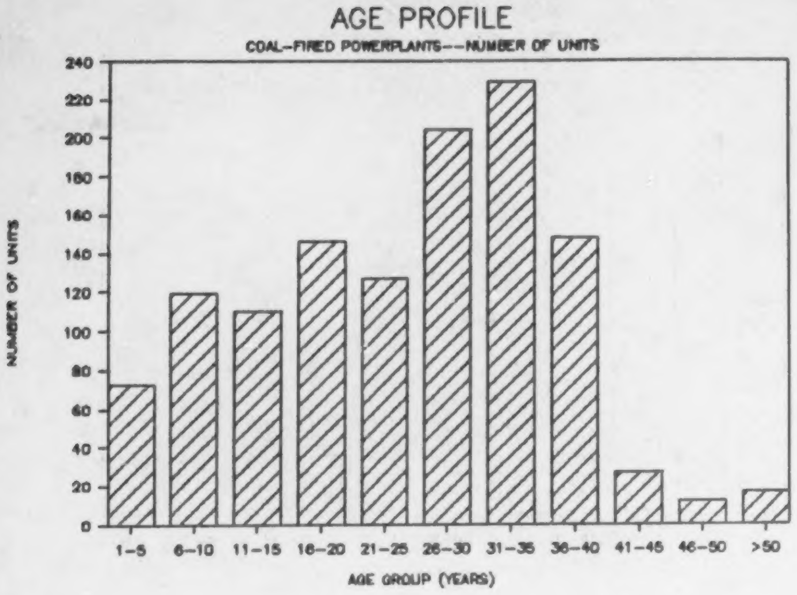


MEGAWATTS

REGION	1-5	6-10	11-15	16-20	21-25	(AGE GROUP) 26-30	31-35	36-40	41-45	46-50	>50	CAPACITY WEIGHT MEDIAN AGE
ECAR	7,147	12,723	19,426	19,266	3,937	9,143	9,206	3,596	464	153	38	16
ERCOT	3,375	8,323	1,779	593	0	0	0	0	0	0	0	8
MAAC	620	1,092	819	8,671	2,538	3,316	1.523	740	59	0	68	19
MAIN	2,381	4,641	7,366	5,781	4,055	4,342	3,205	733	115	2	59	18
MAPP	2,771	7,362	2,995	2,378	1,322	1,776	929	581	33	53	85	11
NPCC	643	0	0	1,406	482	1,784	764	789	177	15	0	28
SERC	7,228	5,640	15,568	11,167	10,201	8,169	9,200	1,170	140	40	0	18
SPP	8,337	11,460	1,318	1,825	630	749	244	43	0	0	4	7
WSCC	5,801	8,402	8,085	5,236	1,843	647	408	166	0	1	10	11
TOTAL	38,303	59,643	57,356	56,323	25,008	29,926	25,479	7,818	988	264	264	TOTAL MW 301,372



NUMBER OF UNITS

(AGE GROUP)

REGION	1-5	6-10	11-15	16-20	21-25	26-30	31-35	36-40	41-45	46-50	>50	MEDIAN AGE
ECAR	14	22	36	52	27	55	71	56	9	4	3	28
ERCOT	6	13	3	1	0	0	0	0	0	0	0	8
MAAC	1	2	1	13	10	17	15	10	2	0	2	28
MAIN	5	13	16	17	23	28	31	16	4	1	2	27
MAPP	9	14	10	14	15	29	22	30	5	4	7	28
NPCC	1	0	0	4	2	12	10	12	3	1	0	33
SERC	11	14	22	25	31	41	62	16	3	1	0	27
SPP	14	20	3	8	7	12	11	2	1	0	0	17
WSCC	12	21	19	12	12	10	7	6	0	1	2	15
												TOTAL UNITS
TOTAL	73	119	110	146	127	204	229	148	27	12	16	1,211

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 1: You have described the Administrations commitment to the deployment of clean coal technologies.

a. In your judgement is S. 879 an appropriate legislative vehicle?

b. Can we expect to receive specific amendments to S. 879 that reflect the Administrations concerns? If so, when?

c. Can we expect to receive a separate legislative proposal from the Administration? If so, when?

Answer a: S. 879 shares the Administration's goal of advancing the demonstration and deployment of clean coal technologies that hold the potential to accelerate the availability of the innovative technologies, and, as such, offers a basis for working towards a bipartisan Clean Coal Technology authorization bill.

b: No, however the Administration is willing to work actively toward a bipartisan Clean Coal Technology Program authorization bill.

c: As previously stated, the Administration does not plan to submit a separate legislative proposal but is willing to work actively with Congress toward developing a bipartisan Clean Coal Technology Program authorization bill.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 2: From the standpoint of the criteria in section 4 (b) of S. 879 to be used in determining whether or not to provide financial assistance, in your judgment,

a. should such selection criteria distinguish between new and existing facilities? If so, should such selection criteria favor existing facilities?

b. will the criteria in S. 879 provide sufficient flexibility to implement the recommendations of the Special Envoys?

c. what additional factors should be considered in awarding financial assistance? Should such factors include geographic diversity?

d. what are the potential conflicts between the recommendations of the Envoys' report and the objectives of the innovative clean coal technology program? For example, the Special Envoys' recommendations place great emphasis on immediate reductions in atmospheric emissions of air pollutants.

e. should S. 879 include as a goal a quantifiable reduction in atmospheric emissions of sulfur oxides or nitrogen oxides, or both?

Answer a: With respect to the issue of new or existing facilities and the Special Envoy's recommendations particularly emphasizing the technologies that would be applicable to existing plants, DOE has interpreted this to mean that proposals for the demonstration of new grass roots plants can be considered if the technology to be demonstrated is capable of retrofitting or repowering existing plants. Further we believe that criteria to favor existing plants should be considered carefully as such use could result in limiting the flexibility of the solicitation and may adversely impact the submission of some promising innovative technologies with significant retrofit or repowering potential.

b: The Special Envoy's criteria are not precise enough for procurement purposes. One of the tasks that DOE must complete in any subsequent solicitation will be to translate the Special Envoys' criteria into specific evaluation criteria. If the Special Envoys' criteria are given the status of a legal requirement a significant amount of flexibility in program implementation would be lost.

c: Additional factors that should be considered in establishing criteria for awarding financial assistance in a subsequent solicitation include:

(1) Extent to which the technology will expand the menu of air pollution control options available to existing coal-fired powerplants;

(2) Extent to which the demonstration plant and/or the commercialized version of the technology can contribute to reductions in transboundary air pollution.

In considering factor (2), the following specific technology attributes highlighted by the special Envoys should be considered:.

o the efficiency of SO_2 and NO_x emissions reduction,

o the cost-effectiveness of the technology in terms of dollars per ton of SO_2 and NO_x emissions reduced, and

- o the potential number of existing sources contributing to transboundary air pollution to which the technology would have retrofit or repowering applicability.

It should be remembered that the core resource base of the United States is widely distributed. To achieve optimum use of this resource the effort expended in formulating factors to be considered in awarding financial assistance should include geographic diversity.

d: Some of the areas or aspects in which the objectives of the Innovative Clean Coal Technology Program have expanded upon the recommendations of the Special Envoys' report are:

(1) amount of program emphasis placed on immediate reductions in emissions, as compared to a longer-term solution to the problem. The position has been taken that conventional technologies now exist to reduce emissions of SO_2 and NO_x. While we agree, we also would point out that such technologies are costly and inefficient often resulting in secondary waste disposal problems. Further there are advocates for selecting demonstration projects that have the greatest potential to reduce transboundary pollution in the short term as a result of the demonstration projects themselves. A better position, we believe, is to select technologies that have the greatest general potential for achieving the Special Envoys' goals whether or not

significant emission reductions in transboundary pollution will result from the demonstration facility.

(2) consideration of utility versus industrial application. The Special Envoys' recommendation is that technologies should be developed that can be used to replace or control sources of emissions which because of their size produce the largest amounts of SO_2 and NO_x emissions. A significant number of these emitters are utility sources. In the Innovative Clean Coal Technology Program, DOE believes that both industrial and commercial demonstration projects should be considered. Technologies most likely will be judged, in part, on the basis of their potential commercial application. Thus utilities applications with a wider commercial distribution are likely to receive more consideration than most industrial applications.

(3) applicability of the demonstrated technology to new sources, as well as existing. The Special Envoys' recommended that the technologies cofunded should be applicable to existing plants. DOE has interpreted this to mean that the demonstrations can be new, grass roots plants if the technology being demonstrated has retrofit or repowering potential.

e: DOE believes that the use of a quantifiable reduction goal in atmospheric emissions of sulfur oxides or nitrogen oxides would be counter productive to achieving the objectives of the Innovative Clean Coal Technology Program. Such a requirement, we believe, would limit the field and reduce the number of participants who would otherwise could submit proposals.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 3:	In your judgment, should any pre-award costs be eligible for inclusion for financial assistance agreement? If so, should completion of negotiations be required before inclusion of such pre-awards costs in any financial assistance agreement?
Answer 3:	Some pre-award costs (i.e., costs incurred by the participant after selection and prior to signing of the Cooperative Agreement) should be eligible for inclusion in the financial assistance agreement. These costs should be reasonable and related to:

- The preparation of material requested by the DOE and identified as required for the negotiation process.

- The preparation and submission of environmental data requested by the DOE to complete the NEPA requirements for the project and which are cost shared by the participant in the ratio established by his proposal.

It is expected that such costs would be reimbursed only upon successful negotiation of the agreement.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 4: The Administration has emphasized cost-sharing by the sponsors of any project receiving financial assistance under S. 879.

a. What types of assets (e.g., land, patent rights, etc.) should be eligible for inclusion in any such cost-sharing agreement?

b. Should existing facilities, equipment, and supplies, or previously expended research or development funds, be eligible for inclusion in any cost-sharing agreement?

Answer a: Cost participation by the proposer may be accomplished by a contribution of either direct or indirect costs, provided such costs are otherwise allowable in accordance with the cost principles applicable to the award. Patents, proprietary data, or prior work should not be valued in determining the cost participation of the proposer in the Cooperative Agreement; land, equipment, and facilities should be considered. The value of these contributions, however, should be determined according to guidelines similar to those used in CCT-1.

b: Contributions, in the form of facilities, equipment, and supplies, or previously expended research or development funds should be considered only to the extent that they would be amortized, depreciated, or expensed in "normal business practices." The definition of normal business practice should be determined by the Secretary and should not necessarily be the practice of any single proposer. Property which has been fully depreciated should not receive any cost-sharing value, except to the extent that it has been in continuous use by the proposer during the calendar year immediately preceding the issuance of the Program Opportunity Notice (PON). For this property, a fair-use value for the life of the project would be determined by DOE.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 5: The Administration has emphasized repayment as a condition for receipt of financial assistance under S. 879 --

a. Should S. 879 provide that repayment be mandatory or should it be a discretionary requirement for negotiation on a project by project basis? Distinguish between the regulated and non-regulated recipients of financial assistance.

b. What assets or sources of revenues should be eligible for use in satisfying or retiring any repayment obligation?

Answer a: The Department's position is that a repayment provision for up to the Government's share of the financial assistance should be included in the Cooperative Agreement, and we would recommend that any legislative proposal make such repayment mandatory. However, enough legislative flexibility should be allowed to DOE to permit us to fashion the repayment provisions in such a way that the interest of prospective participants in the program are not dampened.

b: The assets or sources of revenue that should be considered in subsequent clean coal solicitations would include those that are now considered in the Clean Coal Technology Program. They include revenues generated from royalties, licensing, and leasing of the technology or sale of equipment, continued operation of the demonstration plant beyond the end of the Cooperative Agreement and the sale of the equipment used in the project. In addition to these revenue sources, however, we are considering the use of provisions that would recognize the value of "cost caps" (i.e., agreements that limit the Government's financial exposure in the project).

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 6: It is reasonable to expect that financial assistance agreements will not be finalized on all projects selected for negotiation.

a. On what basis, if any, should the Secretary be able to terminate negotiations?

b. If negotiations are terminated, should funds previously set aside for the project be available for reobligation?

Answer a: If the proposer is unable to provide a committed financial plan and a legally-established entity, along with a committed site, then DOE would have to terminate the negotiations. Other terms and provisions of the PON are negotiable to the extent that the result is not inconsistent with the intent of the PON and the project is in the best interest of the United States and its taxpayers.

b: If negotiations are terminated with any of the nine proposers initially selected, DOE would make additional selection(s) from the alternate list of candidates presently containing twelve active proposals.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 7: It is reasonable to expect that all financial assistance agreements will not necessarily result in completed, operational projects?

a. On what basis, if any, should the Secretary be able to terminate a financial assistance agreement?

b. If such an agreement is terminated should funds previously obligated for the project be available for reobligation?

Answer a: As established in the Program Opportunity Notice (PON), the cooperative agreement may be terminated in whole or in part by mutual agreement of the parties. The Department of Energy (DOE) may terminate the agreement for default, if the participant fails to comply with any of the terms and conditions. Either party may unilaterally withdraw from the project at the completion of any phase. Such withdrawal shall be at no additional cost to either party, that is, beyond their individual project costs at the completion of that phase.

b: If such a withdrawal/termination should occur, the remaining project funds would be applied to additional Clean Coal Technology projects.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 8: The Department's April 10, 1987 budget amendment for Fiscal Year 1988 requests an increase in funding for the existing clean coal program of $350 million from the Clean Coal Technology Reserve. The budget amendment is conditioned on corresponding offsets against other programs.

a. Does the Administration support fiscal year 1988 funding for the current program absent offsetting reductions?

b. Does the Administration support funding for the innovative clean coal technology program absent offsets against other programs?

Answer a: The Gramm-Rudman-Hollings Act requires the Department to comply with deficit reduction requirements in conjunction with any Budget amendment. The offsets were submitted in compliance with the law and consistent with the budget deficit target for FY 1988.

b. In the outyears, the Innovative Clean Coal Technology Program will require the Administration to examine its ongoing projects and priorities and determine where funds can be identified that permit us to remain consistent with the Gramm-Rudman-Hollings deficit reduction goals.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 9: Critical to the eventual success of the clean coal technology program is a pre-assessment of the potential environmental benefits of projects selected for Federal assistance. Reportedly, requests for the environmental impact assessments of the nine selected projects have been denied by the Department, despite two Freedom of Information Act requests.

a. What is the legal basis for these denials?

b. Would you provide for the record the environmental impact assessments of the nine projects selected for negotiations, indicating any materials that have been redacted and the reasons for such reactions?

Answer a: The legal basis for the denials of the information requested in the two Freedom of Information Act requests are contained in the Office of Hearings and Appeals decisions on the requests. Accordingly, enclosed are copies of the original May 30 and August 6, 1986 requests from Mr. David G. Hawkins on behalf of the National Resources Defense Council (NRDC) for the requested information; the June 13 and November 18, 1986 denials by the FOIA denying officials and the August 4, 1986 and January 22, 1987 Decisions and Orders of the DOE Office of Hearings and Appeals denying Mr. Hawkins' appeal for release of the documents.

b: Only after review of the "Appendix J" information required to be submitted by the Participants can DOE determine if an environmental impact assessment is necessary for each of the nine projects selected for negotiations. DOE has to date completed the NEPA review for three projects (i.e., The Babcock and Wilcox Company, The Coal Tech Corporation, and The American Electric Power Service Company Demonstration Projects) and has

NRDC

Natural Resources
Defense Council

1350 New York Ave., N.W.
Washington, DC 20005
202 783-7800

May 30, 1986

BY HAND

#860602012-7

Mr. John H. Carter
Freedom of Information Officer
U.S. Department of Energy
Room 1G051, MA 232.1
1000 Independence Avenue, S.W.
Washington, DC 20585

Re: Freedom of Information Request

Dear Mr. Carter:

Pursuant to the Freedom of Information Act, 5 U.S.C. §552, we hereby request a copy of the following specified portions of completed forms from each proposal received in response to DOE's Program Opportunity Notice for Clean Coal Technology Demonstration Projects (PON Number DE-PS01-86FE60966):

> Tables K-a through K-f; items 4, 7, and 8 (see PON at pages K-5 through K-10)

Please note that each proposal may contain more than one copy of each of the above tables. In that case, we request a copy of the above information from each copy of the above tables in the proposal.

Please note in addition that this request is framed narrowly to permit disclosure of information that will not be identifiable with any specific proposal.

We understand the above information is located in the Office of the Deputy Assistant Secretary for Coal Utilization, Advanced Conversion and Gasification.

Pursuant to the FOI Act and DOE regulations, we request a waiver of any charges or fees resulting from this request: this information is relevant to a demonstration program in a Report of the Special Envoys on Acid Rain that was endorsed by President Reagan in March 1986 and which concerns a subject of significant public interest; NRDC is a bona fide public interest group; this

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122 East 42nd Street
New York, New York 10168
212 949-0049

Western Office:
25 Kearny Street
San Francisco, CA 94108
415 421-6561

New England Office:
850 Boston Post Road
Sudbury, MA 01776
617 443-6300

Toxic Substances
Information Line:
USA: 1-800 648-NRDC
NYS: 212 687-6862

8606[illegible]17-7

information is not related to any administrative proceedings or litigation involving NRDC and the federal government; NRDC will use this information for public education purposes and not to further private commercial interests.

We look forward to your action on this request within 10 working days as provided by 10 CFR §1004.5(d). Thank you for your assistance.

Sincerely,

David G. Hawkins

David G. Hawkins
Senior Attorney

NRDC

Natural Resources Defense Council

1350 New York Ave., N.W.
Washington, DC 20005
202 783-7800

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FOI # 860806072-7

August 6, 1986

BY HAND

Mr. John H. Carter
Freedom of Information Officer
U.S. Department of Energy
Room 1G051, MA 232.1
1000 Independence Avenue, S.W.
Washington, DC 20585

Re: Freedom of Information Act Request

Dear Mr. Carter:

Pursuant to the Freedom of Information Act, 5 U.S.C. §552, we hereby request a copy of the following documents:

1. "Pre-Selection Programmatic Environmental Impact Analysis;" and
2. "Pre-Selection Project-Specific Environmental Review."

These documents are referred to at pp. 13 and 14 of a DOE document entitled "Selection of Proposals for the Demonstration of Clean Coal Technologies Program Opportunity Notice DE-PS01-86 FE60966," signed by Acting Assistant Secretary for Fossil Energy, Donald L. Bauer, on July 24, 1986.

Pursuant to the FOI Act and DOE regulations, we request a waiver of any charges or fees resulting from this request: this information is relevant to a demonstration program in a Report of the Special Envoys on Acid Rain that was endorsed by President Reagan in March 1986 and which concerns a subject of significant public interest; NRDC is a bona fide public interest group; this information is not related to any administrative proceedings or litigation involving NRDC and the federal government; NRDC will use this information for public education purposes and not to further private commercial interest.

#860806072-7

We look forward to your action on this request within 10 working days as provided by 10 CFR §1004.5(d). Thank you for your assistance.

Sincerely,

David G. Hawkins
Senior Attorney

JUN 13 1986

Department of Energy
Washington, D.C. 20585

CERTIFIED - RETURN RECEIPT REQUESTED

Mr. David G. Hawkins
Senior Attorney
Natural Resources Defense Council
1350 New York Avenue, N.W.
Washington, D.C. 20005

Dear Mr. Hawkins:

This letter is in response to your request for information, No. 86060201Z-7, dated May 30, 1986, made pursuant to the Freedom of Information Act (FOIA), 5 U.S.C. §552. In your letter, you requested a copy of certain information contained in proposals submitted to the Department of Energy (DOE) in response to the Program Opportunity Notice (PON) for the Clean Coal Technology Program, which was issued on February 17, 1986 (DE-PS01-86FE60966).

In particular, you requested that the DOE examine each proposal received in response to the PON and provide a copy of the information submitted by each offeror under items 4, 7, and 8 of tables K-a through K-f of Appendix K. You further indicated that your request was "framed narrowly to permit disclosure of information that will not be identifiable with any specific proposal."

Under the PON, DOE solicited proposals for financial assistance required to conduct cost-shared clean coal technology demonstration projects that will lead directly to accelerated commercial availability of these emerging technologies. All proposals that were received on or before April 18, 1986 and that have passed Preliminary Evaluation currently are being carefully and thoroughly evaluated by the Source Evaluation Board, in accordance with the evaluation criteria set forth in the PON. Projects will be selected for award no later the August 1, 1986, and negotiations leading to the actual award of cooperative agreements will follow the project selection announcement.

Among other things, the PON requires, in Appendix K, "Summary Environmental Data for the Commercialized Technology," that offerors include in their proposal information that will allow DOE to evaluate the potential change in the emission of various pollutants assuming the proposed technology is successfully demonstrated and, thereafter, applied to the maximum number of facilities practicable by the year 2010. In order to facilitate this evaluation, the proposer is required to provide information related to: (1) the technical and economic applicability of the commercial version of the proposed technology to new and retrofit markets, and (2) the air, water, solid waste emissions, and water consumption from the proposed technology. The summary applicability and environmental data is to include information regarding the spectrum of commercialized applications. The specific information that is the subject of this request pertains to: (1) market penetration expected for the proposed technology and major market sectors that will have significantly different emission rates or emission reduction potential (item 4); (2) the potential penetration of the proposed technology into each market subsector identified (item 7); and an identification of the type and total amount of pollutants that would be emitted from the facility (item 8).

The PON also states that each offeror is to include in their proposal a public abstract, which, in 500 words or less, provides an overview of the proposed project. The abstracts were to include a description of (1) the proposed project, (2) the specific clean coal technology proposed, (3) the objective, (4) the methodology, (5) the sponsoring organizations, and (6) the timeframes applicable to the project. The offerors were advised that these abstracts might be made available to the public, in whole or in part, and, therefore, should not contain proprietary or confidential business information. On April 21, 1986, DOE announced in a press release that copies of the public abstracts prepared by the offerors were available to the public for inspection and copying. At this time, the public abstracts are the only information from or pertaining to the proposals that has been disclosed to the public.

The DOE is unable to grant your request for this information. This information is being withheld pursuant to 5 U.S.C. §552(b)(4), Exemption 4 of the FOIA, which protects matters that are "trade secrets and commercial or financial information obtained from a person and privileged or confidential." Information submitted by a person is "confidential" for purposes of Exemption 4 if disclosure of the information is likely either to: (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained.

Prior to award of a contract or cooperative agreement, all parts of the proposals submitted in response to a competitive solicitation are exempt from disclosure pursuant to Exemption 4. This determination is based on the fact that such proposals contain trade secrets and commercial and financial information which were obtained from a person and are confidential. The confidentiality determination is based on the fact that disclosures of information from proposals prior to award would allow a competitor to obtain information concerning a pending proposal and use that information to improve its own proposal in this and possible future soliciations. Thus, such disclosures could cause substantial harm to the competitive position of the person whose proposal information was disclosed prior to award, and could undermine the Government procurement process by impairing the Government's ability to obtain proposals in response to future competitive solicitations. In this case, the likelihood of competitive harm from such disclosures is heightened by the fact that DOE previously disclosed the public abstracts from each proposal. It is possible that, in certain instances, the information from Appendix K when combined with the information available in the public abstracts could allow competitors to identify the disclosed information with a specific proposal. Such disclosures are likely to cause substantial competitive harm to the proposers, because it would reveal to competitors the potential market penetration of the proposed technology into various market subsectors as well as the environmental performance characteristics of the proposed technology.

Section 1004.1 of title 10, Code of Federal Regulations, requires the disclosure of records which DOE is authorized to withhold under FOIA, unless DOE determines that such disclosure is not in the public interest. The disclosure of information withheld pursuant to Exemption 4 could constitute a violation of the Trade Secrets Act, 18 U.S.C. §1905, unless the disclosure of such information is otherwise authorized by law. Chrysler v. Brown, 441 U.S. 281 (1979). Since there currently is no statutory authority or DOE regulation which constitutes such authorization by law, disclosure of the records in question is prohibited.

I am the denying official responsible for the determination to withhold the information described above.

Pursuant to section 1004.8 of title 10, Code of Federal Regulations, the denial of a FOIA request may be appealed, in writing, within 30 days after receipt of a letter denying any portion of the request, to the Director, Office of Hearings and Appeals (HG-1), Department of Energy, 1000 Independence Avenue, S.W., Room 6G-030, Washington, D.C. 20585. The written appeal, including envelope, must clearly indicate that a Freedom of Information Appeal is being made, and the appeal must contain all other elements required by title 10, Code of Federal Regulations, section 1004.8. Judicial review will thereafter be available to you: (1) in the district in which you reside; (2) where you have your principal place of business; (3) where the Department's records are situated; or (4) in the District of Columbia.

Sincerely,

Original Signed By:
Jeffrey Rubenstein

Jeffrey Rubenstein
Freedom of Information
Authorizing Official
Office of Procurement Operations

GC-34/LCarlton/bmm/6/13/86/252-6902

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MA-45
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J. Carter (860602012-7) <—
L. Carlton, GC-34
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18 Nov 86

Mr. David G. Hawkins
Senior Attorney
Natural Resources Defense Council
1350 New York Avenue, N.W.
Washington, D.C. 20005

Dear Mr. Hawkins:

This letter is in response to your request for information, No. 86080607Z-7, dated August 6, 1986, made pursuant to the Freedom of Information Act (FOIA) 5 U.S.C. 552. In your letter, you requested copies of the "Pre-Selection Programmatic Environmental Impact Analysis" and the "Pre-Selection Project-Specific Environmental Review" that were discussed in Section III.27, "National Environmental Policy Act (NEPA) Strategy," of the Program Opportunity Notice (PON) for the Clean Coal Technology Program, which was issued on February 17, 1986 (DE-PS01-86FE60966).

Under the PON, DOE solicited proposals for financial assistance required to conduct cost-shared clean coal technology demonstration projects that will lead directly to accelerated commercial availability of these emerging technologies. All proposals that were received on or before April 18, 1986, and that passed Preliminary Evaluation, were carefully and thoroughly evaluated by the Source Evaluation Board in accordance with the evaluation criteria set forth in the PON. Projects were selected for award on July 24, 1986, and negotiations leading to the actual award of cooperative agreements are in progress.

Among other things, the PON required that offerors include in their proposals information that would allow DOE to evaluate the potential changes in the emissions of various pollutants, assuming the proposed technology is successfully demonstrated and, thereafter, applied to the maximum number of facilities practicable by the year 2010. In order to facilitate this evaluation, the proposer was required to provide information related to: (1) the technical and economic applicability of the commercial version of the proposed technology to new and retrofit markets, and (2) the air, water, solid waste emissions, and water consumption from the proposed technology. The summary applicability and environmental data were to include information regarding the spectrum of commercialized applications.

The specific documents that are the subjects of your request contain information provided by the proposers, and are based upon information that pertains to: (1) market penetrations expected for the proposed technologies and major market sectors that will have significantly different emission

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rates or emission reduction potentials, (2) the potential penetrations of the proposed technologies into each market subsector identified, and an identification of the types and total amounts of pollutants that would be emitted from the facilities.

We now have completed our review of these documents, and have determined that the portions listed below may be provided to you. These materials are hereby enclosed:

I. Pre-Selection Programmatic Environmental Impact Analysis:

- o Pages i, ii;
- o Pages 1-1 through 2-2 inclusive;
- o Page 2-3 with one line deleted;
- o Pages 2-14 and 2-15;
- o Pages 2-36 and 2-37;
- o Pages 2-61 and 2-62;
- o Pages 2-78 and 2-79;
- o Pages 2-109 and 2-110; and
- o Pages 3-1 through 3-5 inclusive (one paragraph deleted on p. 3-2).

II. Pre-Selection Project-Specific Environmental Review:

- o Page 1-1

DOE is unable to grant your request for the remainder of the information. This information is being withheld pursuant to 5 U.S.C. 552(b)(4), Exemption 4 of the FOIA, which protects matters that are "trade secrets and commercial or financial information obtained from a person and privileged or confidential." Information submitted by a person is "confidential" for purposes of Exemption 4 if disclosure of the information is likely either to: (1) impair the government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained.

Prior to award of a contract or cooperative agreement, all parts of the proposals submitted in response to a competitive solicitation are exempt from disclosure pursuant to Exemption 4. This determination is based on the fact that such proposals contain trade secrets and commercial and financial information which were obtained from a person and are confidential. The confidentiality determination is based on the fact that disclosures of information from proposals prior to award would allow a competitor to obtain information concerning pending proposals and use that information to improve its own proposal in this and possible future solicitations. Thus, such disclosures could cause substantial harm to the competitive position of the person whose proposal information was disclosed prior to award, and could undermine the government procurement process by impairing the government's ability to obtain proposals in response to future competitive solicitations.

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Section 1004.1 of Title 10, Code of Federal Regulations, requires the disclosure of records which DOE is authorized to withhold under FOIA, unless DOE determines that such disclosure is not in the public interest. The disclosure of information withheld pursuant to Exemption 4 could constitute a violation of the Trade Secrets Act, 18 U.S.C. 1905, unless the disclosure of such information is otherwise authorized by law (Chrysler v. Brown, 441 U.S. 281 (1979)). Since there currently is no statutory authority or DOE regulation which constitutes such authorization by law, disclosure of the records in question is prohibited.

Portions of the documents have also been withheld pursuant to Exemption 5, 5 U.S.C. 552(b). Exemption 5 provides that an agency may exempt from public disclosure "inter-agency or intra-agency memoranda or letters which would not be available by law to a party other than agency in litigation with the agency." Exemption 5 incorporates the deliberative process privilege which protects advice, recommendations, and opinions that are pre-decisional and part of the decision-making process of the agency. In applying Exemption 5, a distinction is made between memoranda prepared to assist an agency decision-making in arriving at a decision and post-decisional memoranda setting forth the reasons for an agency decision that has already been made. Pre-decisional memoranda are exempt from disclosure while post-decisional memoranda must be disclosed.

The information deleted from the documents pursuant to Exemption 5 represents the environmental analysis of proposals submitted to DOE. The criteria used by the members of the Source Evaluation Board to evaluate the proposals were set forth in the PON. The evaluation comments discuss the strengths and weaknesses of each proposed project. These views do not reflect a final agency opinion but were presented to and evaluated by the Source Selection Official to select proposals for further cooperative agreement negotiations. Thus, the information is pre-decisional and part of a deliberative process of the agency protected by Exemption 5.

The disclosure of the information that falls within Exemption 5 would not be in the public interest because it could stifle open and frank communications between the Source Selection Official and the Source Evaluation Board and thereby interfere with the agency's decision-making process.

I am the denying official responsible for the determination to withhold the information described above.

Pursuant to Section 1004.8 of Title 10, Code of Federal Regulations, the denial of an FOIA request may be appealed, in writing, within 30 days after receipt of a letter denying a portion of the request, to the Director, Office of Hearings and Appeals (HG-1), Department of Energy, 1000 Independence Avenue, S.W., Room 6G-030, Washington, D.C. 20585. The written appeal, including envelope, must clearly indicate that a Freedom of Information Appeal is being made, and the appeal must contain all other elements required by Title 10, Code of Federal Regulations, Section 1004.8. Judicial review

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will thereafter be available to you: (1) in the district in which you reside; (2) where you have your principal place of business; (3) where the Department's records are situated; or (4) in the District of Columbia.

Sincerely,

Jack S. Siegel
Deputy Assistant Secretary
for Clean Coal, Combustion
and Conversion Systems

Enclosures

bcc: FE-22 Chron & Rdg.
FE-20 (2)
Abel Lopez, GC-43

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PRE-SELECTION PROGRAMMATIC ENVIRONMENTAL IMPACT ANALYSIS

The Clean Coal Technology Program Opportunity Notice (CCT PON, section III.27) described in some detail the nature of a programmatic environmental impact analysis to be conducted by DOE. This report contains a description of that analysis, and its results. The analysis has the following characteristics:

- it is comparative - emissions from proposals are compared to baseline emissions from conventional technologies
- it is regional - to the extent data were provided by proposers or reasonable assumptions could be made regarding the geographical distribution of the proposed technology
- it reflects the proposer's estimated U.S. market potential of the commercialized version of the proposed demonstration unit (it does not reflect the impacts of the demonstration unit itself)
- it reflects environmental information furnished by the proposer on forms consistent with Appendix K of the PON, unless other data are identified in the narrative on each proposal in Chapter 4 of this section
- it contains a qualitative discussion of projected environmental impacts, unresolved environmental issues, data gaps, and the time frame of environmental effects.

This report consists of the following four chapters:

- Chapter 1: Key Energy and Environmental Issues. This chapter is a brief overview of the types of generic, regional problems which a fully commercialized technology may ameliorate or aggravate.
- Chapter 2: Environmental Characteristics of Emerging Technologies. This chapter contains brief discussions of emerging technologies for which submissions were received in response to the PON, and passed preliminary evaluation, brief descriptions of the submissions, and the strengths and weaknesses of each proposal relative to the environmental criterion for the commercial version of the proposed process.
- Chapter 3: Methodology. This chapter describes the basic process by which emission changes from proposed technologies were quantified.
- Chapter 4: Results. This chapter presents the quantitative results, any DOE assumptions inconsistent with the submitted data, and the qualitative discussion relating these results to key issues in Chapter 1.

In addition, more detailed information regarding the water consumption rates and other environmental characteristics of emerging technologies can be found in Appendix 1.

Chapter 1: KEY ENERGY AND ENVIRONMENTAL ISSUES

Introduction

In order to understand the environmental importance of a technology's residuals, one must first appreciate the key environmental issues which might relate to that technology (i.e., unresolved environmental issues and long-term or short-term environmental effects). The purpose of this chapter is to convey that appreciation. This chapter is not an energy primer, nor an environmental primer. Rather it offers pragmatic environmental information believed to be relevant to the classes of technologies for which proposals have been submitted. Although a large body of objective data are presented, it should be understood that the basic decisions regarding what issues are most important are subjective. Additionally, although a large energy operation can have site specific difficulties with a large number of environmental regulations, this discussion assumes judicious siting and examines only those issues which may pose generic or regionally significant environmental concerns.

Three groups of issues are presented:

- Air quality issues
- Water quality issues
- Solid waste disposal issues.

The greatest emphasis is placed on air quality issues, because for the classes of sources considered, they appear to be the most important and the most complex. Water issues receive somewhat less emphasis; and solid waste issues are emphasized least.

Air Quality Issues

Air quality management is governed by a complex set of Federal, State, and local laws, ordinances, and regulations. Federal involvement dates back to the Air Quality Control Act of 1955, although the bulk of today's regulations were mandated by the Clean Air Act of 1970 and its amendments in 1977. In the Clean Air Act, Congress established the principle that air quality management is primarily a state and local government responsibility. The Federal role was to set objectives, National Ambient Air Quality Standards (NAAQS), and then to ensure that state programs were adequate to achieve the goals. The Act also required the Federal Environmental Protection Agency (EPA) to promulgate regulations for new sources, including New Source Performance Standards (NSPS) and regulations for the Prevention of Significant Deterioration of air quality (PSD), and to provide mechanisms for state agencies to implement these programs. In cases where states fail to adopt adequate implementation procedures for these programs, enforcement responsibility defaults to EPA. Because of the interstate character of mobile sources (vehicles), Congress gave EPA primary responsibility for regulating those sources.

The key air quality issues evolving from these regulations, and relevant to the Clean Coal Technology Program, are deemed to be:

- Criteria pollutant problems
- Acid rain
- Visibility impairment
- Carbon dioxide and global warming.

Criteria pollutants include the six pollutants for which national ambient air quality standards have been set. They are listed, along with the standards, in Table 1-1. "Primary" standards relate to health effects. "Secondary" standards relate to welfare, or economic, effects. A general overview of how well we are meeting these standards is gained from examining trends in the Pollutant Standard Index. Invented in 1976 to provide a simple numerical measure of air quality, a value of 100 means that an air quality standard is being exceeded; a value of 400 means that an emergency exists. Figure 1-1 shows PSI trends for four representative cities for the period 1976-1984. Note that in 1976 these cities reported unhealthy air (PSI > 100) on about one day in three. Eight years later this frequency was reduced by an order of magnitude. Note also that Total Suspended Particulates (TSP) and Sulfur Dioxide (SO2) ceased to be significant problems in these cities in about 1980, but that Carbon Monoxide (CO), and especially Ozone (O3) continue to be problems. A large body of data support the generalization that CO and O3 are the principle criteria pollutant problems. It should be noted that CO is almost entirely a mobile source problem, and is unrelated to the CCTP. CO will therefore receive no further analysis in this report. Ozone, on the other hand, is related to both mobile and stationary emission sources. Ozone is a secondary pollutant (not emitted in large quantities itself) which forms when Nitrogen Oxides (NOX) and hydrocarbons react in the presence of sunlight. The trend in ozone concentrations is downward, but is not dramatic. Figure 1-2 shows a 12% decrease in the second highest daily maximum concentration from 1975 to 1984. Figure 1-3 shows that the number of violations of the standard decreased by about 1/3 over the same period. A set of plots in Figure 1-4 offers greater insight into the nature of the ozone problem in 19 metropolitan areas, and highlights the "problem areas" of the northeast, Gulf coast, and Southern California. These areas are so widely separated that the ozone issue should be considered national in scope. It has been reported that about 85 million people live in the 35 metropolitan areas now at or above 0.15 ppm ozone (recall that the standard is 0.12 ppm).(Inside EPA, 2/28/86)

Data on rural ozone concentrations are not plentiful. EPA staff are reportedly seeking a much lower secondary standard than now exists, because of suspected crop effects. Rural ozone is critical to the CCT program because the best approach to controlling rural ozone is likely to be NOx reduction. In urban areas, NOx reduction usually contributes to ozone reduction, but is thought to provide less ozone reduction than control of ozone's other precursor, hydrocarbons. The relevance of all this to the CCT program is that NOx control may have high value as a means to reduce ozone concentrations and thereby provide both health benefits and economic benefits.

It is useful to examine trends in pollutant emissions over time. Figures 1-5 thru 8 present long term emissions of SO2 and NOx (1900-1980). Figures 1-9 thru 11 present more recent data, along with a disaggregation by source category, for TSP, SO2, and NOx. The trends indicated by these figures are that:

- TSP (particulate matter) emissions have decreased significantly over the past few years;
- SO2 emissions have fluctuated between 20 and 30 million tons per year since about 1920;
- NOx emissions increased exponentially from the beginning of the century through 1975, but have been relatively constant for the last decade.

To summarize, the available data on criteria pollutant emissions, ambient concentrations, and trends indicate that the primary environmental concern regarding stationary source emissions relates to ozone levels, which are determined by nitrogen oxide and hydrocarbon emission rates. Hydrocarbons are not emitted in significant quantities from the classes of sources responding to the CCT PON.

In addition to concerns about certain criteria pollutants, some concern has been raised about three additional air quality issues: acid rain, visibility impairment, and global warming due to carbon dioxide. The most significant of these issues for the CCT program is acid rain.

In response to concerns expressed over acid rain, Congress enacted the Acid Precipitation Act of 1980 (P.L. 96-294). The law created the Interagency Task Force on Acid Precipitation (ITFAP) and provided for a 10 year research program to address the important aspects of the acid rain phenomenon. The purpose of the law was to coordinate Federal research and to provide findings to Congress. The most important aspect of the research program is probably its effort to define the nature and extent of the acid rain problem; i.e., to quantify adverse effects. It should be noted that acid rain is perceived to be most serious in eastern North America and certain European nations, and that the pollutants causing greatest concern are sulfur dioxide and nitrogen oxides. In the Joint Report of the Special Envoys on Acid Rain, (January 1986) a succinct state-of-the-science section was included to provide an American perspective on what is known regarding adverse effects of acid rain in the U.S. The findings are summarized below:

- Based on EPA's recent eastern lake survey, about 4% of the survey lakes were found to have a pH below 5.0. (Many fish species cannot live at this pH.) 19% of the survey lakes had alkalinities below 50 micro-equivalents per liter, indicative of sensitivity to additional acid deposition. No midwestern lakes were found with pH below 5.0. A number low pH lakes were found in Florida, but the influence of acid deposition on these lakes is suspect.
- It is not certain in what circumstances acid deposition may have significant detrimental effects on forest resources. Forest damage has been documented in the U.S., but at this time the relationship between acid rain and forest damage in the U.S. is only conjectural.
- Acid rain has the potential to degrade building materials, such as marble, limestone, carbonate-based paints, and metals. The extent and economic significance of acid deposition to building materials damage in the U.S. are not known.
- Acid rain is not known to cause direct human health effects. There is concern that effects may result indirectly from ingestion of heavy metals mobilized by acidity. However, no incidents of such indirect effects have been reported in the U.S.

The Envoys' report offered little insight into possible crop damage from acid deposition, but research has generally found that most species exhibit no adverse effects in field studies at current deposition rates. Simulated acid rain experiments have produced a combination of no effect, adverse effects, and beneficial effects, depending on the crop species (1984 Annual Report to Congress, CEQ).

The overall assessment of the seriousness of acid rain is best represented by the ultimate recommendations of the special envoys. In addition to continued research, they suggested government co-funding of demonstations of new, less expensive, technologies to control SO2 and NOx.

With respect to visibility impairment, the 1977 Clean Air Act Amendments expanded on more general language in the 1970 Act and directed EPA to implement a program to protect and enhance visibility in Class I Federal areas (e.g., National parks). The resulting program applies to both new and existing stationary sources, but will have its greatest impact on new facilities. The details and procedures associated with this program are beyond the scope of this overview. The most important thing to note is that visibility can be impaired by small particles or by colored gases. This implicates particulate matter, SO2, and NOx emissions, all of which are associated with energy facilities. In addition, it should be noted that Class I areas are found all over the U.S., so the program is not regional in nature. This regulatory program is still evolving, so it is premature to conclude the extent to which visibility regulations will require pollution controls in excess of those programs which already limit emissions of particulate matter, SO2, and NOx.

The final air quality issue to be discussed is global warming due to increasing concentrations of carbon dioxide (CO2). This so-called greenhouse effect is caused by the selective filtration of infrared radiation by CO2; energy from the sun passes through the atmosphere, but cannot re-radiate to space when converted to the infrared spectrum. Combustion of fossil (carbon-based) fuels and deforestation of less developed countries are the major causes of increased levels of CO2. The relevance to the CCTP is that less efficient energy conversion processes generate more CO2 per unit of useful energy than more efficient technologies. Because the CO2 emission trend is extremely gradual (significant impacts are possible by 2050), and because most of the CO2 generation is beyond the control of the U.S. (much less the CCT program), the influence of the CCT program on CO2 global CO2 emissions will be negligible.

Water Issues

The landmark legislation for addressing water quality issues was the Federal Water pollution Control Act of 1972, although it should be noted that the Act has been amended several times since 1972, and that additional amendments are now being discussed in Congress. In general, degradation of water resources has been arrested, but the statutory goal of restoration of waters to "fishable and swimmable" quality has not been achieved (Environmental Quality 1984, CEQ, p82). Like air quality management, water quality management is primarily a state responsibility. Pollutants of concern are represented by those most often reported by the states (see Figure 1-12). Principal sources of these pollutants are identified in Table 1-2. Energy activities are not central to any of these pollutants, with the exception of pH (which is affected by atmospheric emissions and mine drainage). Energy facilities can affect the temperature of water bodies, and thereby adversely affect aquatic organisms. However, most large new energy facilities are equipped with cooling towers which minimize such impacts. In short, most potential water quality problems associated with large energy facilities are routinely managed to an acceptable degree.

A major water-related environmental concern which does concern energy facilities, however, is the limited availability of water in the arid west. Energy facilities consume large quantities of water, both for process use and for cooling purposes. This water must come from either surface water or underground water supplies.

Figure 1-13 shows the flowrate of large rivers in the U.S. Figure 1-14 depicts areas where water consumption exceeded supply in 1975. Figure 1-15 shows areas where stream flows were below levels needed to sustain normal water uses (recreation, navigation, hydro power, waste assimilation, treaties and contracts, and aquatic ecosystems) in 1975. These figures all indicate the relative abundance of surface water in the east and Pacific northwest, and its relative scarcity in the southwest.

With respect to underground water supplies, anecdotal evidence of concern can be gained from an examination of the Ogallala aquifer, which lies under the states of CO, KA, NE, NM, OK, SD, TX, and WY. The Ogallala is the largest aquifer in the U.S. More than 70,000 wells are lowering the water level faster than it can be replenished. Water levels have fallen over 100 feet in parts of KA, NM, OK, and TX. From 1977 to 1990, the Texas portion of the aquifer is expected to decline 30% in volume (Environmental Quality 1984, p. 316). In general, annual withdrawals from western aquifers exceed recharges by over 22 million acre-feet, about 50% of the flow of the Colorado River (Ibid). Rough estimates of published information regarding the water consumption intensity of various energy activities are contained in Appendix 1.

To summarize the water-related environmental issues sensitive to energy facilities, one can conclude that most potential regional impacts of energy development are routinely manageable; but that the use of water by such facilities in the southwest can be a major problem.

Solid Waste issues

Existing energy activities are generally not regarded as major generators of hazardous wastes. Future facilities, expecially synfuels processes which restructure large hydrocarbon molecules, have the potential for generating hazardous materials, but this is a process-specific pheonomenon and is beyond the scope of this analysis. This does not mean that the issue is not important; only that its degree of seriousness will not be quantified. However, both existing and new energy technologies are known for generation of large quantities of non-hazardous wastes. Of the 900 million tons of coal mined in 1984, for example, approximately 10% (the ash) required disposal by some means. Advanced coal preparation processes, which tend to discard some of the useful coal as well as most of the ash, have the potential to generate large quantities of solid wastes. Flue gas treatment systems likewise can generate copious quantities of semi-liquid or relatively dry wastes, depending on the particular technology. In theory, all of these wastes can be managed in an environmentally benign manner. In reality, there is always the risk that a reasonably designed waste containment system can fail in its purpose, and that groundwater can be contaminated.

The foregoing suggests that quantitative evaluation of solid wastes generated by energy related activities may be of limited utility in estimating the risk of environmental damage from the waste material. Of greater interest is the qualitative consideration of the nature of the waste (does it have the consistency of toothpaste or of soil), and its relative magnitude (twice as much, half as much, etc.) versus the baseline technology displaced. And for more sophisticated chemical processes, it is important to know if cracking reactions involving bond-breaking in large aromatic coal-based molecules are taking place, and if hydrogenization of the product may result in elimination of complex and potentially hazardous compounds.

Table 1-1
National Ambient Air Quality Standards (NAAQS)

Pollutant	Primary (Health Related)		Secondary (Welfare Related)	
	Averaging Time	Concentration	Averaging Time	Concentration
TSP	Annual Geometric Mean	75 ug/m^3	Annual Geometric Mean	60 ug/m^3[a]
	24-hour	260 ug/m^3	24-hour	150 ug/m^3
SO_2	Annual Arithmetic Mean	(0.03 ppm) 80 ug/m^3	3-hour	(0.50 ppm) 1300 ug/m^3
	24-hour	(0.14 ppm) 365 ug/m^3		
CO	8-hour	(9 ppm) 10 mg/m^3	Same as Primary	
	1-hour	(35 ppm) 40 mg/m^3	Same as Primary	
NO_2	Annual Arithmetic Mean	(0.053 ppm) 100 ug/m^3	Same as Primary	
O_3	Maximum Daily 1-hour Average	0.12 ppm (235 ug/m^3)	Same as Primary	
Pb	Maximum Quarterly Average	1.5 ug/m^3	Same as Primary	

[a] The annual geometric mean is a guide used in assessing implementation plans to achieve the 24-hour standards of 150 ug/m^3.

Note: The standards are categorized for long- and short-term exposure. Long-term standards specify an annual or quarterly mean that may not be exceeded, short-term standards specify upper limit values for 1-, 3-, 8-, or 24-hour averages. The short-term standards are not to be exceeded more than once per year. For example, the ozone standard requires that the expected number of days per calendar year with daily maximum hourly concentrations exceeding 0.12 parts per million (ppm) be less than or equal to one.

Table 1-2

Sources of Pollution

Pollutant/ Possible Sources	Pollutant Category
BOD/DO	Municipal waste water treatment plants; industries (particularly pulp and paper mills); combined sewers; natural sources
Bacteria	Municipal waste water treatment plants; combined sewers; urban runoff; feedlots; pastures and rangelland; septic systems; natural sources.
Nutrients	Municipal waste water treatment plants; agriculture; septic systems; silviculture; combined sewers; construction runoff.
Suspended solids/ turbidity	Agriculture; urban runoff; silviculture; construction runoff; mining; industries; combined sewers.
Total dissolved solids	Agriculture; mining; urban runoff; combined sewers.
pH	Atmospheric deposition; mine drainage.
Ammonia	Municipal waste water treatment plants; combined sewers.
Toxics	Industries; municipal waste water treatment plants; agriculture; land disposal of wastes; silviculture; urban runoff; spills; combined sewers.

Source: U.S. Environmental Protection Agency, *National Water Quality Inventory: 1984 Report to Congress* (Washington, D.C.: 1985)

Figure 1-1

PSI TRENDS BY POLLUTANT FOR FOUR SMSAs

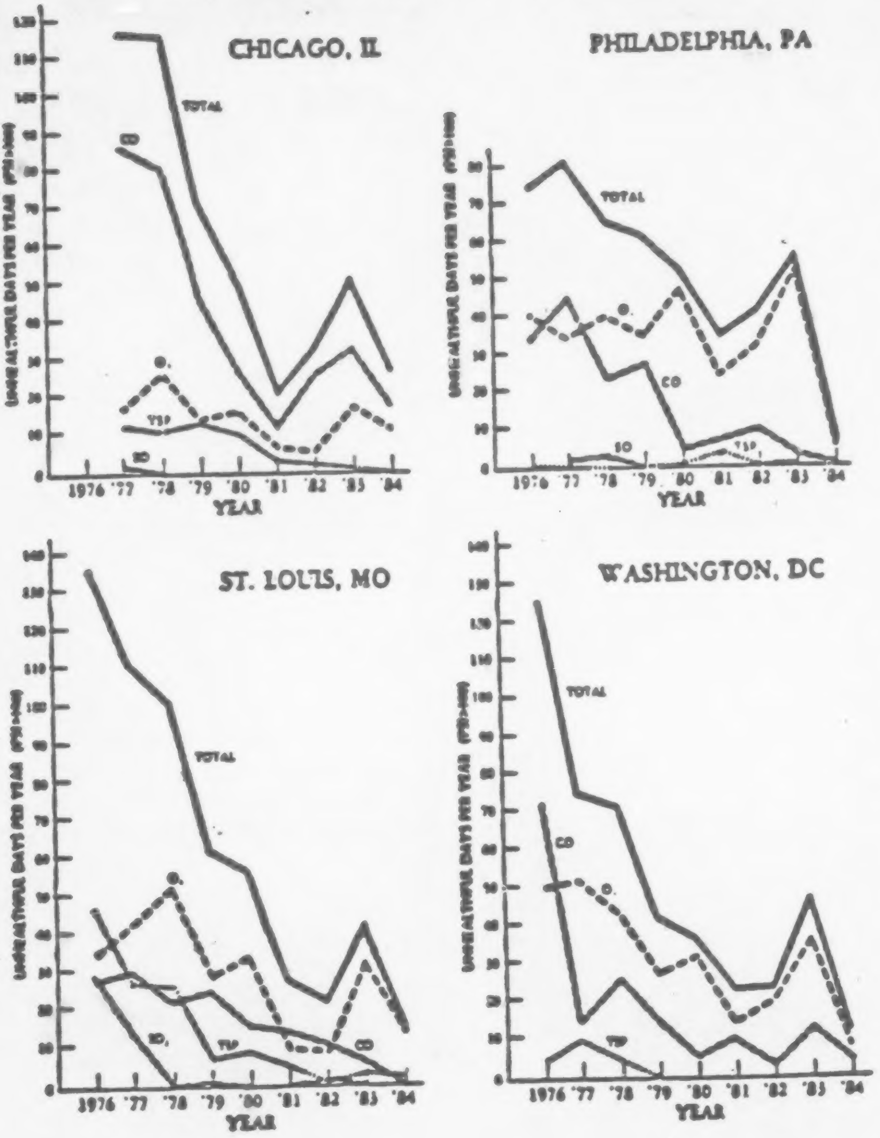


Figure 1-2
NATIONAL TREND IN THE COMPOSITE AVERAGE OF THE SECOND HIGHEST DAILY MAXIMUM 1-HOUR OZONE CONCENTRATION AT NAMS SITES
1975 - 1983

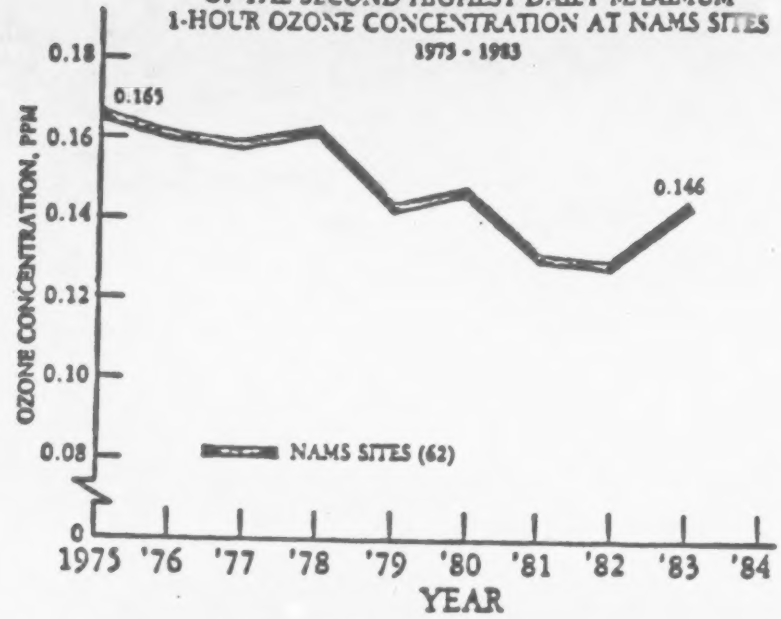
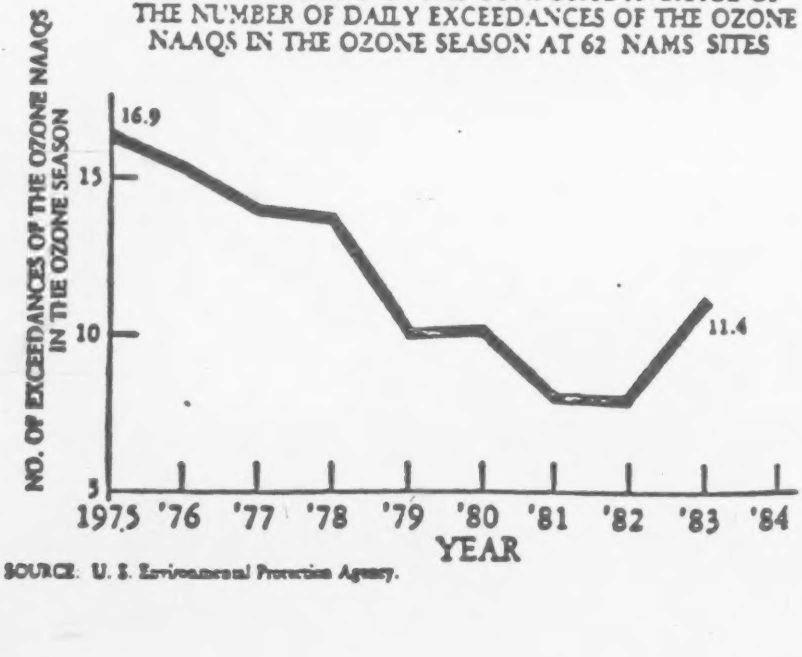


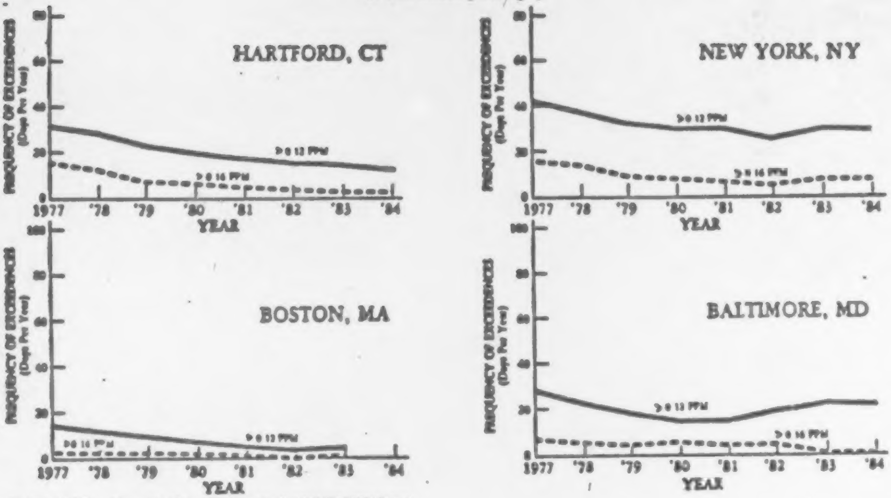
Figure 1-3
NATIONAL TREND IN THE COMPOSITE AVERAGE OF THE NUMBER OF DAILY EXCEEDANCES OF THE OZONE NAAQS IN THE OZONE SEASON AT 62 NAMS SITES



SOURCE: U. S. Environmental Protection Agency.

Figure 1-4

OZONE (O_3) TRENDS BY SMSA
(3-Year Running Averages)



SOURCE: Roy F. Weston, National Air Quality Data System (based on U. S. EPA SAROAD data).

Figure 1-4 (cont.)

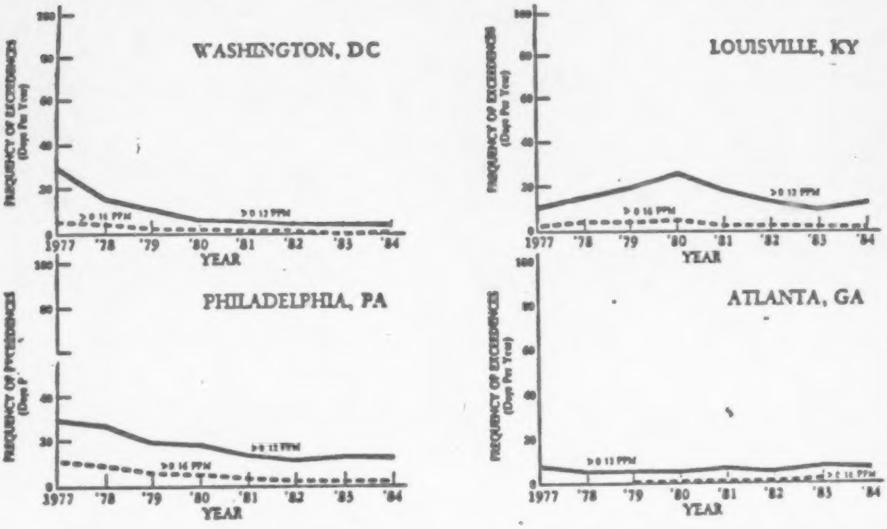


Figure 1-4 (cont.)

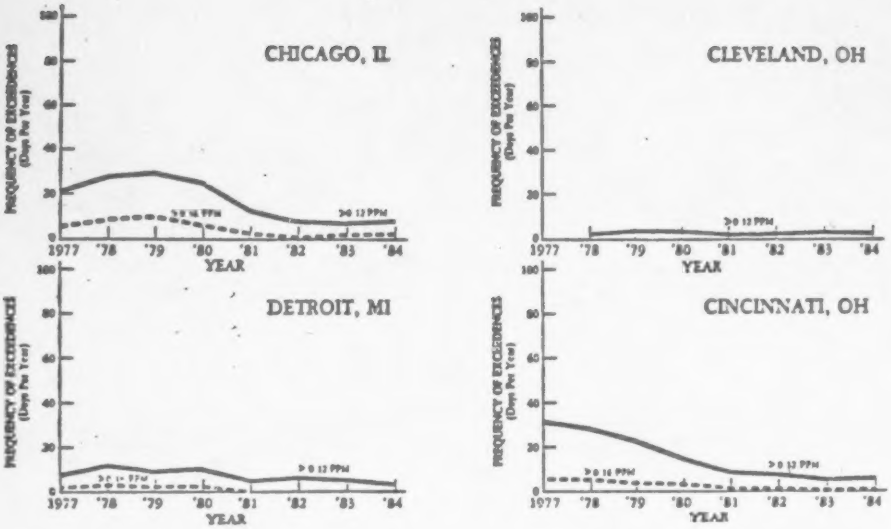


Figure 1-4 (cont.)

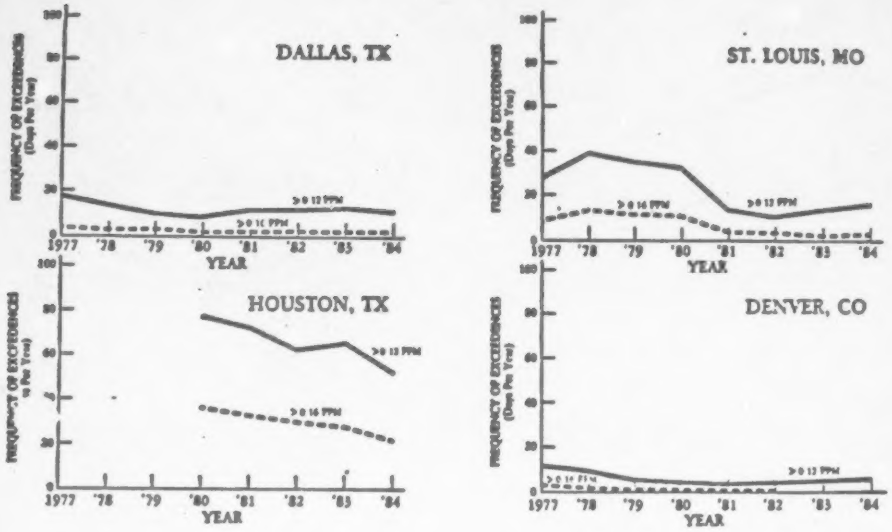
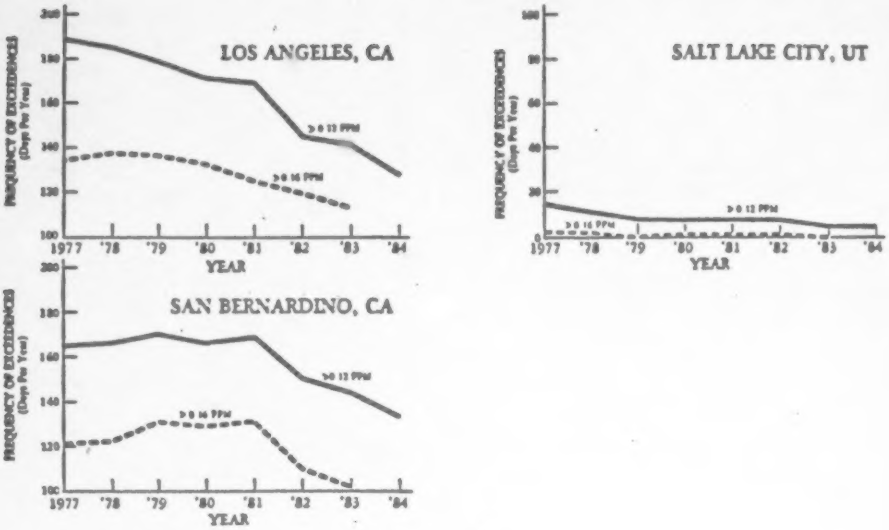


Figure 1-4 (cont.)



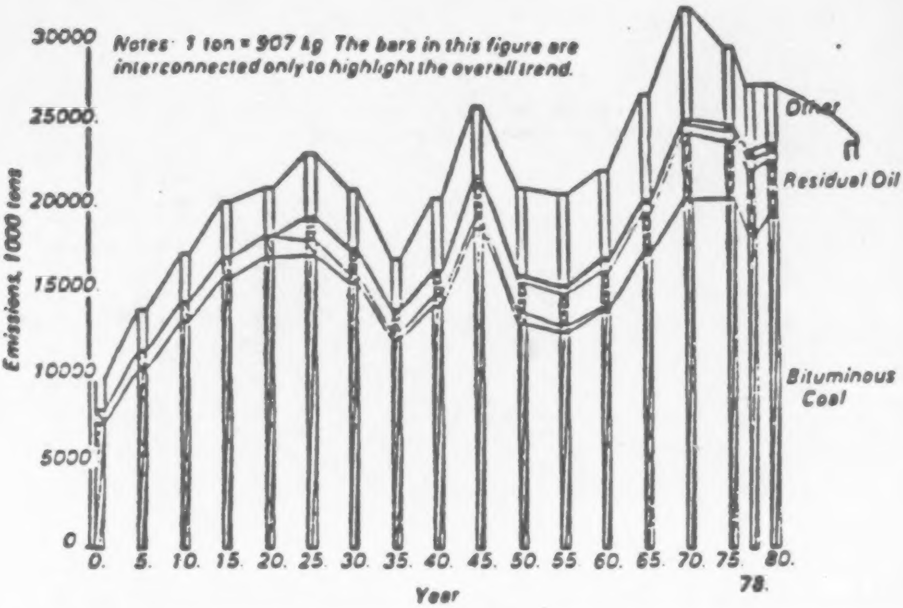


Figure 1-5 Overall trend in SO_2 emissions from 1900 to 1980 for the U.S and by fuel type for each study year.

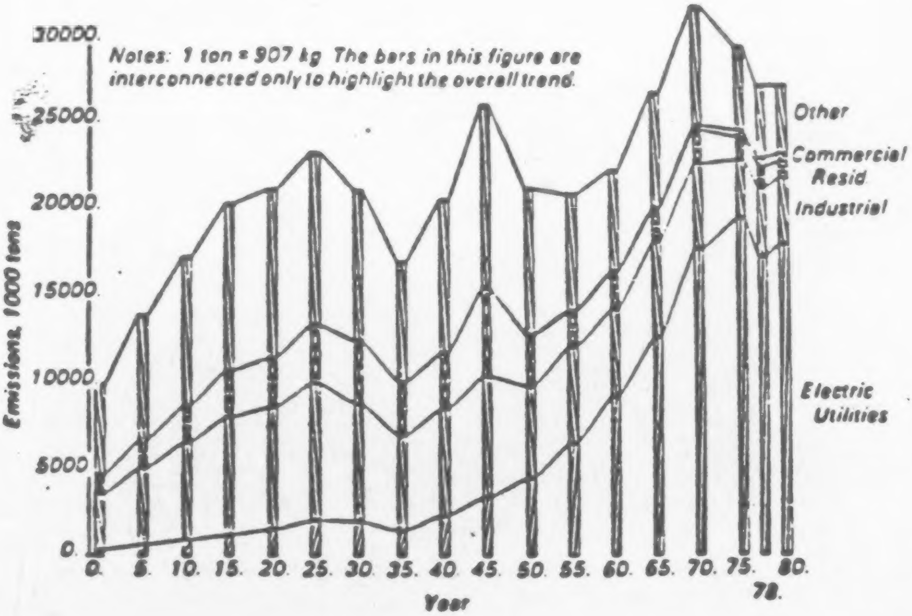
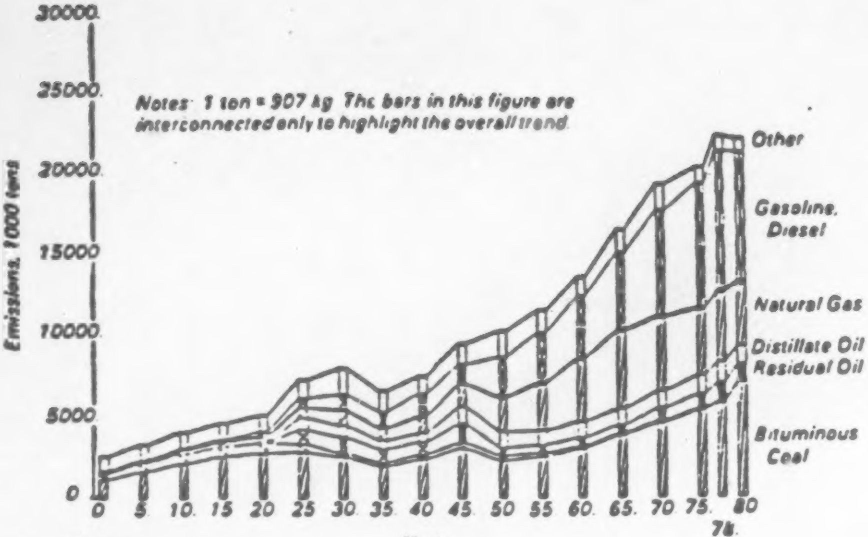
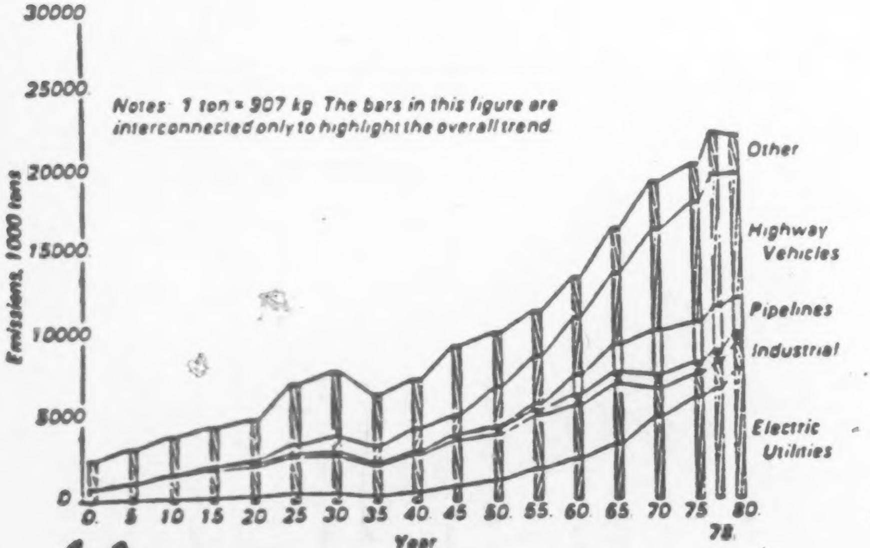


Figure 1-6 Overall trend in SO_x emissions from 1900 to 1980 for the U.S. and by source category for each study year.



1-7

Figure Overall trend in NO_x emissions from 1900 to 1980 for the U.S. and by fuel type for each study year.



1-8

Figure Overall trend in NO_x emissions from 1900 to 1980 for the U.S. and by source category for each study year.

National Particulate Emission Estimates, 1975-1984.

(million metric tons/year)

Source Category	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Transportation	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.3
Fuel Combustion	2.7	2.5	2.5	2.6	2.5	2.4	2.4	2.2	1.9	2.0
Industrial Processes	5.0	4.4	4.0	4.0	3.8	3.2	2.8	2.4	2.2	2.5
Solid Waste	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3
Miscellaneous	0.7	1.0	0.8	0.8	0.9	1.1	0.9	0.7	1.1	0.9
Total	10.4	9.7	9.1	9.2	9.0	8.5	7.9	7.0	6.7	7.0

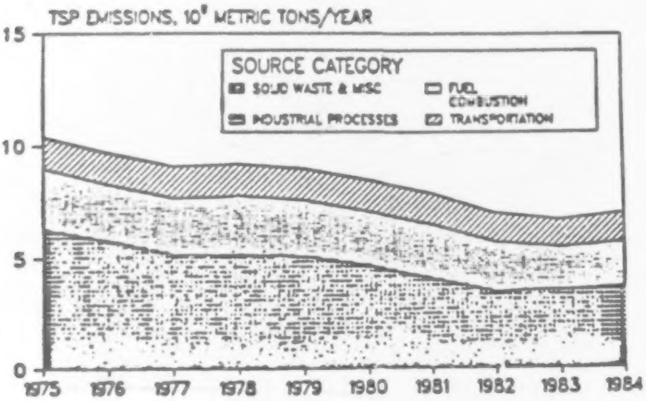


Figure 1-9 National trend in particulate emissions, 1975-1984.

National Sulfur Oxide Emission Estimates, 1975-1984.

(million metric tons/year)

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Source Category										
Transportation	0.6	0.7	0.8	0.8	0.9	0.9	0.8	0.8	0.8	0.9
Fuel Combustion	20.3	20.9	21.1	19.6	19.4	18.8	17.8	17.3	16.7	17.3
Industrial Processes	4.7	4.6	4.4	4.1	4.2	3.5	3.7	3.2	3.1	3.1
Solid Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	25.6	26.2	26.3	24.5	24.5	23.2	22.3	21.3	20.6	21.4

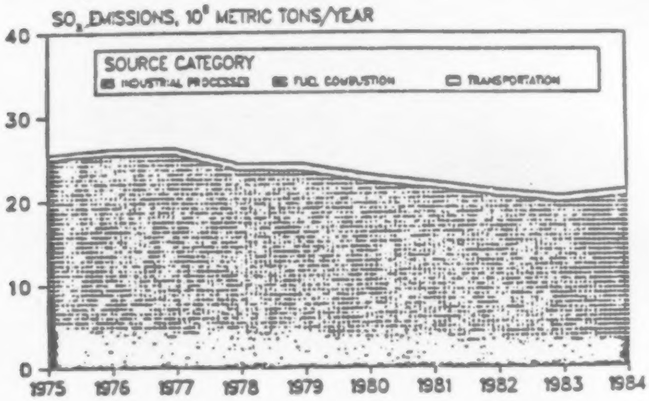


Figure 1-10 National trend in sulfur oxide emissions, 1975 - 1984.

National Nitrogen Oxide Emission Estimates, 1975-1984

(million metric tons/year)

Source Category	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Transportation	8.9	9.3	9.5	9.7	9.6	9.2	9.3	8.9	8.6	8.7
Fuel Combustion	9.4	10.0	10.5	10.3	10.5	10.2	10.2	10.0	9.6	10.1
Industrial Processes	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6
Solid Waste	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Miscellaneous	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2
Total	19.2	20.3	21.0	21.0	21.1	20.4	20.5	19.7	19.1	19.7

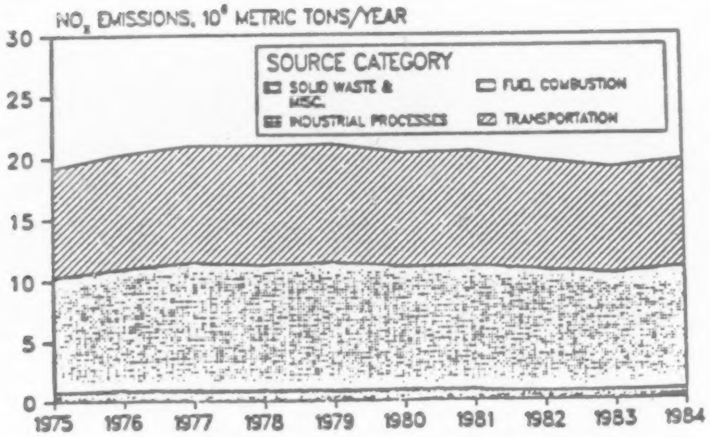


Figure 1-11 National trend in emissions of nitrogen oxides, 1975-1984.

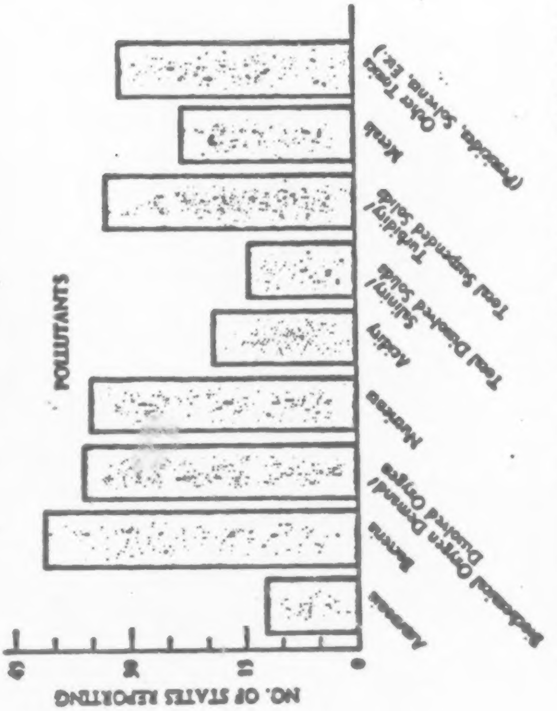
Lake Acres Meeting the Fishable/Swimmable Goal of the Clean Water Act

State	Assessed Lake Area (Acres)	Percent Fishable/Swimmable
Delaware	1,517	92
Kentucky	338,214	100
Maryland	20,696	100
Mississippi	495,191	96
Nebraska	107,726	99
New Hampshire	185,620	85
North Carolina	315,335	81
Rhode Island	16,520	96
South Carolina	440,282	72

Source: U.S. Environmental Protection Agency, *National Water Quality Inventory: 1984 Report to Congress* (Washington, D.C.: 1985).

Figure 1-12

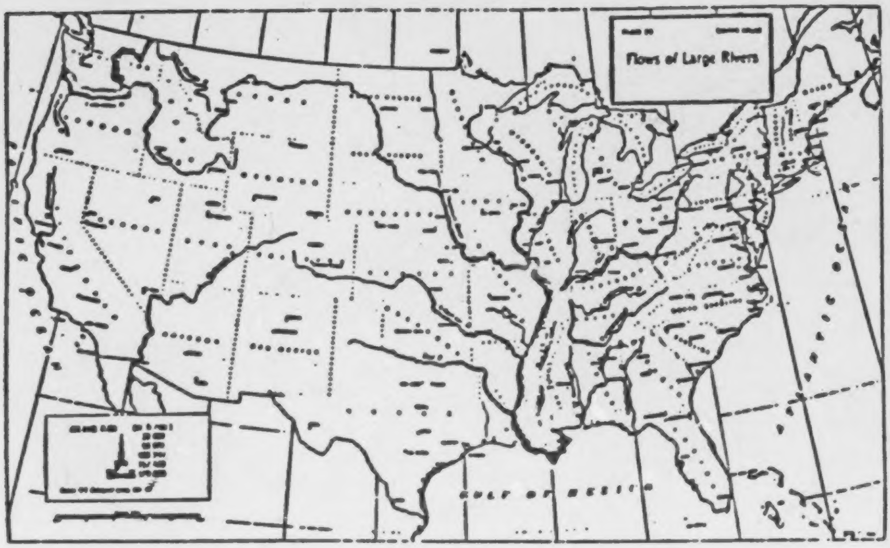
POLLUTANTS MOST WIDELY REPORTED BY THE STATES



SOURCE: U.S. Environmental Protection Agency, National Water Quality Inventory: 1984 Report to Congress (Washington, D.C.: 1985).

Figure 1-13

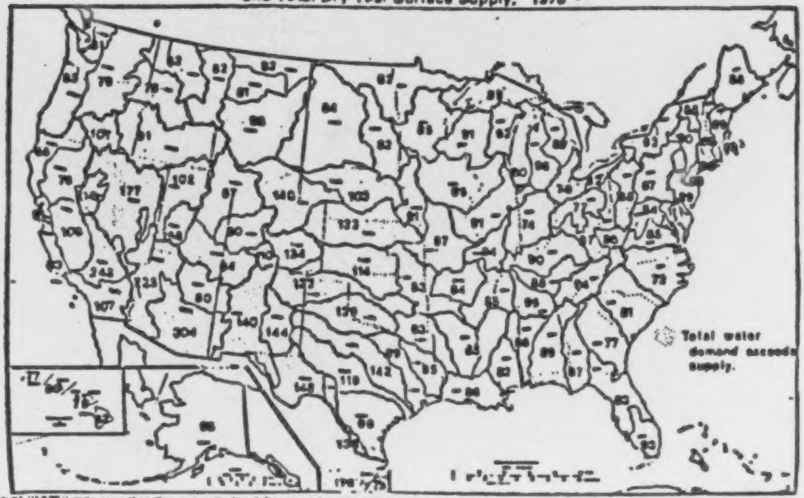
Flows of Large Rivers


Flows of Large Rivers
GULF OF MEXICO

Source: Geraghty and Miller, *Water Atlas of the United States* (1973).

Figure 1-14

Total Use (Consumptive Use plus Instream Flow Use) as a Percentage of Total Average Year Streamflow and Total Dry Year Surface Supply, "1975"*

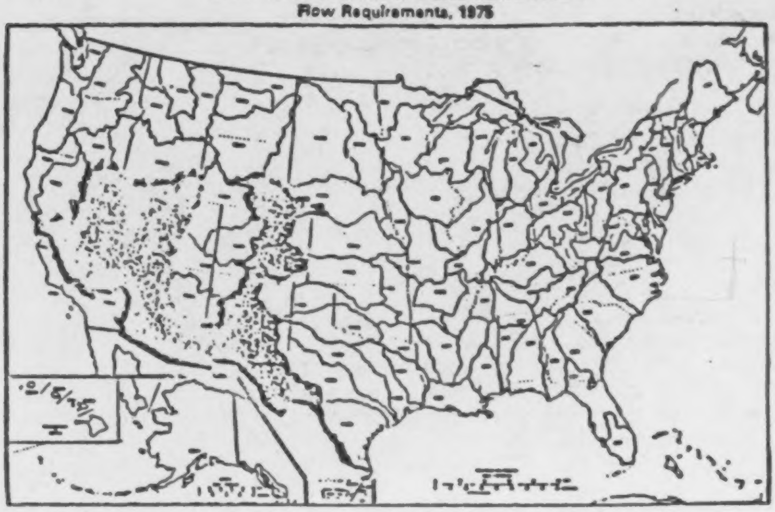


*The use of "1975" indicates that this is a calculated figure and is not a direct estimate

Source: [illegible] Cooperative Instream Flow Service Group, *Instream Flow Methodologies for Regional and National Assessments*, Instream Flow Information Paper No. 7, November, [illegible]

Figure 1-15

States Where Streamflow Is Less Than Instream Flow Requirements, 1975



Source: Bayha, Keith, Cooperative Instream Flow Service Group, *Instream Flow Methodologies for Regional and National Assessments*, Instream Flow Information Paper No. 7, (December, 1978).

Chapter 2: Environmental Characteristics of Emerging Technologies

This chapter contains a brief discussion of the major environmental characteristics of emerging technologies relevant to the Clean Coal Technology Program. These include:

- Advanced Combustors.
- Coal Preparation.
- Flue Gas Cleanup.
- Fluidized Bed Combustion.
- Fuel Cell.
- Gasification.
- Industrial Processes.
- In-Situ Gasification.
- Liquefaction.

Each discussion is followed by a brief description of each project proposed, in that category, and the strengths and weaknesses of the proposal relative to the environmental criterion for the commercial version of the proposed process.

ADVANCED COMBUSTION

The "advanced combustion" technologies proposed offer an approach whereby emission reduction is achieved in the combustion process itself through advanced combustor design, boiler modification, or introduction of sorbents into the combustor. Additional removal can be achieved by using coal preparation to first reduce sulfur and ash in the fuel to be fired.

Advanced combustion technologies can be used in a wide range of applciations including utility, industrial and commercial boilers. They can be used for both retrofit and new installations and can, in some cases, be utilized to allow boilers burning oil or gas to be converted to coal, reducing the consumption of premium fuels.

The primary advanced combustion technology under development (and proposed here) involves slagging cyclone combustors that have potential for 70 to 90 percent SO_2 reduction relative to uncontrolled emissions when burning the same coal in a pulverized coal boiler. This is achieved by introduction of limestone sorbent into the combustor or into the hot combustion gases exiting the combustor and passing into the boiler. If injected into the combustor, most of the limestone (and captured sulfur) exit with the molten slag which is a solid waste. This solid may require oxidation to convert the CaS to $CaSO_4$ so that H_2S is not involved when the solid waste contacts water.

If sorbent is injected in the hot combustion gases, or if significant amounts of sorbent are carried into the boiler, it must be captured in the particulate clean-up system for the boiler. In general, a baghouse or ESP will be needed which will permit the overall particulate removal to achieve the utility or proposed industrial NSPS. Removal of ash as slag prior to the boiler can reduce particulate emissions for retrofits. Typical slag rejections are 80 to 90 percent. The NO_x reduction is achieved in the slagging cyclone combustor by fuel staging i.e., the combustor is operated substiochiometrically with combustion being completed in the boiler where additional air is introduced. Overall, NO_x reduction of 50 to 70 percent relative to wall fired PC combustors can be achieved thereby reducing NO_x below the NSPS. The advanced slagging combustors also have potential to replace existing cyclone boilers which are very high NO_x emitters. Technological alternatives for achieving NO_x reductions on existing cyclone boilers is highly limited since they cannot be fitted with low NO_x burners.

Other technologies can be used in advanced combustion systems to permit environmental goals to be achieved. Deep physical coal cleaning prior to combustion can generally achieve a maximum of 40 to 60 percent sulfur reduction (depending on the ratio of pyritic to organic sulfur in the coal). Reburning can be used in the boiler in conjunction with the staged cyclone combustor to achieve additional NO_x reduction (up to about 50 percent further reduction).

2-2

Combustion of deeply cleaned coal (physical beneficiation) can reduce emissions from retrofits by 40 to 60 percent as discussed before without the need for capital-intensive modifications to the boiler. Particulate emissions can be reduced since the ash load into the ESP or baghouse is reduced; however, ash composition (and gas composition) can be affected which might decrease ESP efficiency. Additional benefits (and problems) can accrue by shifting the solid waste disposal problems from the power plant to the preparation plant. Significant loss of coal BTU's (10 to 20 percent) can occur in the cleaning process which can increase the quantities and nature of solid waste.

Four proposals were classified as advanced combustion technologies. Proposal

However, the primary objective is to develop a combustion data base for deeply cleaned coals.

Summaries of the technologies proposed in this category follow.

Strengths and weaknesses for Criterion 1A from the PON for the 4 advanced combustion projects are also attached.

2-3

COAL PREPARATION

The "coal preparation" technologies proposed offer an approach to upgrade mined coal or waste products into a cleaned coal product which can be used in a wide variety of combustion applications where coal is normally utilized. Coal contains mineral matter which results in ash during combustion and sulfur in both pyritic and organic forms. Physical beneficiation processes, based on differences in the properties of the organic coal matrix and the mineral matter contained in the coal, can achieve moderate to high efficiency (above 90%) of removal for the mineral portions including pyritic sulfur and ash. To accomplish this, the coal must be ground to fine sizes to liberate the encapulated mineral portions. Processes using moderately fine grinding and separation based on differences in density are generally termed "deep" physical coal cleaning. Processes using very fine grinding and surface sensitive properties (microbubble flotation, selective agglomeration, etc.) are often termed "advanced physical beneficiation." The overall sulfur removal efficiency is dependent on the pyritic sulfur fraction in the feed material. For coals this typically is 40 to 60% with the rest of the sulfur being primarily in the organic form. Thus, the best advanced physical beneficiation processes rarely exceed 50% sulfur removal. Ash can be reduced to nearly any desired level to produce a fuel that can substitute for oil or gas, but typical final ash levels of 2 or 3% are usually considered to be acceptable. Tail end particulate removal equipment will be used in almost any combustion application to meet local or national standards.

Fine grinding of coal to achieve high liberation of mineral matter introduces a number of new environmental considerations. Transportation of the fine coal requires special techniques to reduce problems with "dusting" and uncontrolled combustion. Removal of moisture from the fine coal so that it can be handled as a dry solid introduces a significant energy penalty since the filter cake can contain up to 30% moisture. If thermal drying is employed, cleanup devices are needed if coal is the fuel. Use of oil or gas involves consumption of premium fuels.

Several approaches have been used to improve the handling and environmental aspects for finely ground and cleaned coals. These include briquetting, and slurrying - sorbents such as limestone or dolomite can be added to the briquettes to capture sulfur (50 to 70% depending on the amount of sorbent).

The wastes from coal cleaning can present environmental risk if handled improperly. These risks include acid run-off, and slides and fires at the impoundment. Technology is available and is used at modern cleaning plants to adequately dispose of the solid waste and to neutralize acid leachate. Inadequate waste disposal methods were often used in the past, resulting in gob piles and slurry ponds which now presents an environmental risks at a number of sites. These waste piles and ponds often contain significant carbon fractions and can serve as a feedstock for improved coal cleaning technologies. Although coal can be recovered from an otherwise unusable resource, the preparation schemes often have a very low BTU recovery and significant waste products will remain. Recovery operations can disturb a long dormant pile or pond with somewhat unpredictable environmental results. The sulfur and ash contents of the waste piles is usually much higher than that of the parent coal. The preparation scheme is normally designed to produce a product that is similar in characteristics to the parent coal. The resource base for coal waste products is relatively small and highly dispersed so serious environmental consequences are not expected to be serious. The advanced recovery technologies are also applicable to the reject fines stream from conventional plants to recover additional coal.

In addition to cleaning of sulfur and ash, technologies are under development for reduction of organic sulfur using chemical or biological methods to remove sulfur from the coal matrix. When used in conjunction with physical cleaning, overall sulfur removal of 70 to 90% removal can be achieved. Ninety percent removal is needed to produce a fuel capable of meeting the NSPS for high sulfur coal. Lower overall removal can be useful for achieving local standards or possible future standards for retrofits. The biological organic sulfur technology proposed is capable of removing the thiophrenic sulfur portion of the organic sulfur and will generally achieve a 20% increase over physical methods for removing sulfur.

FLUIDIZED BED COMBUSTION

The fluidized bed combustion technologies proposed offer an approach to burn coal to produce steam and electricity for utility and industrial use and reduce SO_2 or NO_x emissions in the combustor itself. In a fluidized bed, solid, liquid, and/or gaseous fuel together with inert material (for example, sand silica, alumina, or ash from the fuel) are kept suspended in a combustion chamber through the action of fluidizing air distributed below the bed. The fluidization suspension can be achieved through either the bubbling-bed or circulating-bed concept. The bubbling-bed concept attempts to prevent solids carryover by maintaining the fuel and inert material in the center of the combustor. The circulating-bed concept encourages solids carryover through high velocity air which entrains and returns the solids to the combustor for additional combustion.

Fluidization promotes the turbulent mixing conditions required for good combustion, the extent of which depends on the size of the particles, the bed temperature, and the fluidizing velocity. The resulting improvement in mixing allows generation of heat at a substantially lower and more uniformly distributed temperature - typically 1500-1600°F. Thus, a properly-sized combustion chamber will release heat at an equivalent level of a conventional boiler, but at lower temperature without any theoretical loss in efficiency. By including a suitable sorbent as part of the bed material - such as limestone or dolomite - the SO_2 released during combustion can be adsorbed, eliminating the need for downstream scrubbers. By operating at low temperature -- well below the required for generation of thermal NO_x -- emissions of NO_x are substantially reduced.

The reactions take place to accomplish SO_2 removal: limestone is calcined to produce calcium oxide and this then combines with SO_2 to form calcium sulfate. The optimum sulfur capture occurs at the 1500-1600°F temperature range. Thus, there are performance trade-offs in maintaining high SO_2 removal and high combustion efficiency. And by including a suitable sorbent as part of the bed material - such as limestone or dolomite -- the SO_2 released during combustion can be absorbed, eliminating the need for downstream scrubbers except for a fabric baghouse for particulate collection.

Air emissions of AFB technology based on a significant number of operating hours at Georgetown University and other units are as follows:

ENVIRONMENTAL EMISSIONS
(lb/MBtu)

Pollutant	Utility NSPS(1)	Industrial NSPS(2)	Industrial NSPS(3)	Emissions
NO_x	.6	.7	.7	.2 - .5
SO_2	Reduction of 70%-90% as mined with max. of 1.2	1.2	Proposal Pending	.7 - 1.2
Particulate	.03	.1	.05 (w/o FGD)	.01 - .05

(1) 250 MBtu/HR and greater
(2) 250 MBtu/HR and greater
(3) 100 MBtu/HR and greater

Emission data based on numerous operating hours shows that AFB technology readily meets the NO_x, SO_x, and particulate emission requirements of the existing new source Performance Standards as well as the proposed.

Pressurized Fluidized Bed Combustion (PFBC) involves the burning of coal in a bed of limestone (calcium carbonate) or dolomite (calcium magnesium carbonate) inside a furnace operated at elevated pressure; bed temperatures normally are in the range of 1550-1750°F. The bed material, or sorbent, is fluidized (suspended) by the injection of air at the bottom of the bed. Sulfur dioxide (SO_2) released during combustion of the coal reacts with the sorbent and forms a solid sulfate which can be discharged from the systems as a dry solid waste along with the coal ash.

Characteristics of PFBC which offer advantages over other competing technologies for utility applications include high efficiency (conservation of resources), superior environmental performance, ability to burn a wide variety of fuels including high sulfur coals within environmental emission limits and modularity with no great cost penalty for loss of economies of scale. PFB also has potential as a retrofit technology capable of pollution control and capacity boosting for existing coal-fired powerplants and as a repowering technology for existing oil and gas-fired steam plants.

There are nine proposals classified as fluidized bed comstion technologies.

Two of them are for pressurized fluidized bed combustion. These are for utility scale circulating FBC. Two are for variations of industrial/commercial scale FBC. One is for an industrial scale unit to operate an anthracite culm.

The last unit is for an industrial scale unit that would burn the tailings for a coal preparation facility to pre-heat the feedwater for a utility boiler.

Summaries of the proposals in the category follow:

FLUE GAS CLEANUP

The "flue gas cleanup" technologies proposed offer an approach for reduction in SO_2 and NO_x emissions from new and retroift utility sources. They may also have application for larger industrial boilers. These technologies all involve "dry" processes for capture of sulfur dioxide. They offer significant technical advantages over the commercially available "wet" scrubbers that use limestone or lime slurries producing substantial quantities of sold waste. The dry technologies are especially attractive for retrofit installations where space requirements and availability of land for waste disposal can limit the application of wet scrubbers at many sites. The dry technologies are especially attractive for retrofits where remaining boiler life is lower than for new units since the dry technologies generally have much lower capital costs.

The dry cleanup technologies capture sulfur with a solid sorbent. The sorbent may be injected into the boiler-Limestone Injection Multistage Burner (LIMB) and use limestone, dolomite, hydrated lime, etc. The solid product $CaSO_3/CaSO_4$ plus ash is collected in the ESP or baghouse. The substantially increased solids load as a result of the sorbent addition can result in decreased performance for the particulate collection device and these technologies often involve upgrades of the ESP, replacement with a baghouse, or special techniques such as humidification of the flue gas to improve performance. The LIMB-type technologies are capable of typically 50 percent sulfur capture at a Ca/S ration of 2.5. Higher removal can be achieved with the addition of more sorbent with corresponding impact on process economics.

"Duct injection" is a new development involving injection of dry hyrdated lime in the flue gas duct upstream of the ESP or baghouse along with flue gas humidification. The sulfur dioxide removals of over 70 percent have been achieved at Ca/S ratios of 2.5 in small scale testing. The humidification also assists in maintaining ESP performance. This technology is potentially attractive to retrofit utilities since it avoids injecting solids into the boiler (which can increase the tendency for fouling and slagging) and is low in capital costs.

Spray dryers have been used fairly extensively for "dry scrubbing" of flue gas from low sulfur coal combustion. In addition to producing a dry waste, the spray dryer technology is less capital intensive than wet scrubbing and may have retrofit potential. The data base for high sulfur coals is limited to 20MWe industrial boilers where SO_2 removals of over 90 percent have been achieved.

The dry solids product resulting from these technologies are considered to be more manageable than sludges produced in many wet scrubbing processes. These solids can be disposed of in suitable landfills and are not classified as "hazardous" at present. If high fractions of unreacted aklalies remain, special considerations may be needed in disposal.

The NO_x reduction can be achieved through the use of low NO_x burners that essentially use fuel staging to reduce NO_x. Typical NO_x reductions are 50 percent for the better burners. They are generally low in capitol and operating expense and can be retrofitted to many boilers.

"Reburning" involves an additional fuel staging step where a hydrocarbon fuel is added above the boiler flame zone in a "reburning" zone followed by additional burnout air. Methane (natural gas), propane, methanol and even coal have all been successfully tested as reburning fuels. The reburning fuel is generally 10 to 20 percent of the coal BTU's fed to the boiler. Premium reburning fuels such as natural gas, of course, involve the use of scarce resources. Methane, in addition to being more effective than coal as a reburning fuel, also results in decreased SO_2 emissions in porportion to the amount of coal displaced. Preburning with natural gas can typically reduce NO_x by 50 percent. In conjunction to the NO_x reduction that first results from low-NO_x burners, reduction of up to about 70 percent can result.

Regenerable scrubbing processes do not produce a throw away solid waste - they produce saleable products such as elemental sulfur or sulfuric acid. In the dry sorbent approach, a solid sorbent is used to absorb SO_2 and NO_x. Upon regeneration at higher temperatures using a reducing gas (produced from coal) sulfur and nitrogen compounds are released which are subsequently destroyed or converted to saleable products using commercially available technologies. Use of a fluidized bed absorber to contact the flue gas with the solid sorbent can result in generation of fines through attrition which can be carried into the particulate capture devices and may inpact its performance. This is a function of the additional particulate carryover and its chacteristics. In general, this should be manageable. The fluidized bed design is physically very large which can limit applicability in small, tight retrofits.

SURFACE GASIFICATION

The surface gasification technologies proposed convert coal (in the presence of an oxidant, air or oxygen, and steam) to a fuel gas primarily composed of carbon monoxide and hydrogen. The fuel gas is burned in boilers to raise steam or in gas turbine combustors to directly generate electricity. In one proposal, the carbon monoxode/hydrogen mixture is furhter processed to make methanol. In the production of the fuel gas from coal, the ash materials are discharged as dry solids and the fuel-bound nitrogen and sulfur are converted to ammonia (NH_3) and hydrogen sulfide (and other organic sulfides such as, COS and mercaptans). Upon combustion the ammonia and hydrogen sulfide will be converted to nitrogen oxides and sulfur dioxide, respectively.

The benfit of the gasification technologies is that the gaseous sulfur and nitrogen compounds can be removed before combustion using either wet scrubbing or high temperature absorption reactions.

Hydrogen sulfide removal can be achieved by chemical or physical absorption after gas cooling or by chemical absorption on metal oxides at high temperature (1000 to 12000°F). These absorption processes can remove greater than 99 percent of the gaseous sulfur compounds before combustion of the gases. The sulfur species absorbed in chemical solutions (cold cleanup) can be recovered as elemental sulfur or converted to sulfuric acid. From the metal oxide sorption processs (hot cleanup), the sulfur compounds can be recovered as sulfur or converted to sulfuric acid or solid sulfates such as calcium sulfate, which can be ultimately disposed by landfilling.

Two of the proposals provide for sulfur compound capture within the gasifier by the addition of limestone (or dolomite). Capture levels of approximately 90 percent are possible using this method and further capture ("polishing") can be achieved by treating the fuel gas with the metal oxide absorption process to exceed 99 percent total sulfur removal.

Nitrogen compounds (principally ammonia) are generated in the gasification process and, depending on the gasifier operating temperature, are contained in varying amounts in the fuel gas. With fixed-bed gasifiers, the highest ammonia levels are produced (lowest temperature reactor) and lesser amounts are produced in fluid-bed reactors and the lowest amount in entrained reactors (which have the highest operating temperature). The nitrogen compounds are easily removed in cold cleanup systems by disolution in water and are subsequently recovered as saleable ammonia for fertilizer applications. Fuel gas, after cold cleanup, contains a small enough level of ammonia that, upon combustion, produces NO_x emissions far below NSPS emission limits. With hot gas cleanup systems, the ammonia passes through into the final fuel and NO_x emissions must be controlled by combustion modifications or external de-NO_x processes. In either treatment, the fuel gas can meet current NSPS limits.

In three of the proposals steam generation is not required since the process steam is extracted from that generated by the waste heat from the gas turbine exhaust. In the other three, steam for the gasification process would require a separate coal-fired boiler. Emissions from the boiler would be typical of such an installation and would require conventional control schemes for compliance.

When the fuel gas is burned in a gas turbine to produce electricity, the removal of entrained particulate matter must be controlled to a low level to protect the gas turbine. In this case, the exit gases from the combustor are well below NSPS particulate emission limits and the capture solids are disposed as solid wastes along with the primary ash discharge from the gasifier. Then the fuel gas is directly burned in a boiler, the suspended solids will be controlled in the boiler discharge gas by conventional means. In this case, the level of input solids will be significantly below the level in coal and will require less total removal to achieve compliance.

The solid wastes from the gasifier will be coal ash which can be disposed off in the same manner as coal-fired boiler ash. In the two proposals which inject limestone into the gasifier, the solids will contain calcium sulfides. It will be necessary to oxidize these solids to convert sulfides to sulfates which are inert and can be landfilled (the sulfide waste will present leading problems and would be unacceptable as landfill).

One proposal uses a cold water scrubbed cleanup system. In this case, the waste waters will require treatment to remove organic compounds before discharge. This proposal provides for the conversion of a portion of the gas to methanol. The methanol process will produce a class of emissions which are not significant (see also the Liquefaction Section).

As a class, gasification processes can produce tars and oils during early stages of the gasification reactions. In the proposals, the gases are maintained at high temperature (greater than 1000°F) and directly burned at this temperature. The tars and oils which are produced are maintained in the vapor phase and serve as fuel; hence, no emissions of the tars and oils occur from the process.

The six proposals received in the gasifier category are described in the project summaries which follow. The strengths and weaknesses for criterion 1A from the PON for these six proposals are also provided below.

COAL LIQUEFACTION

The coal liquefaction technologies proposed offer an approach to provide liquid fuels from coal for a wide variety of market applications. Both direct and indirect liquefaction can be used to produce finished fuels which are esentially not distinguishable from petroleum products. The plants themselves can be designed to satisfy almost any environmental standard.

Direct liquefaction technologies generally involve (hydro) cracking of the coal molecules, either thermally or catalytically, to produce smaller molecules which can then be upgraded to specification fuels where essentially all heteroatoms (N, S, O) are removed by reaction with hydrogen and particulate matter is eliminated. The final liquid fuels have molecular structures very similar to petroleum products and have about the same biological activity. If the process is designed to produce solid or heavy liquid boiler fuels, the molecular structures more closely resemble the parent coal structures (highly condensed aromatics) or typical coal "tars" and exhibit biological activity. Precautions in handling these fuels must be employed and they are only suitable for the utility or large industrial markets.

Different approaches have been proposed to produce liquid fuels via direct liquefaction. They differ in the reactor conditions and solvents used. The solvent can be generated internally and recycled or can be secured from other sources, such as petroleum products (heavy oil, resid, etc.). In this case the approach is termed coprocessing and the coal and oil are upgraded together and serve as a feed to existing or new refineries to produce refinery-slate products.

Emissions from the plants themselves can be reduced to very low levels through proper design. Sulfur is converted to saleable elemental sulfur, oxygen in the coal is generally reacted with H_2 to form water, nitrogen is hydrotreated to form NH_3 which is saleable, and mineral matter ends up in a bottoms product which is used to produce hydrogen in a gasifier or is burned in a boiler. In either case the mineral matter is converted to a refractory-like slag or fly ash products which are expected to be non-hazardous. Wastewater treatment technologies, such as those used in refineries or in coal gasification plants, can be used to eliminate nearly all phenols, NH_3, and other compounds. The plants can be designed to reuse the wastewater (zero discharge) with blowdowns evaporated to small quantities of solid salt products which can be disposed of at approved disposal sites.

Indirect liquefaction involves first converting the coal to gaseous products issuing a coal gasifier. Use of the high temperature Texaco gasifier eliminates production of tars and converts mineral matter to a gasifier slag. Plant emissions are controlled as for most surface gasification systems and sulfur and nitrogen are recovered as described above.

Catalytic synthesis of liquid products such as methanol is employed which in itself involves no significant emissions aspects. The liquefaction step can also be integrated into an IGCC-type system with the synthesis section being operated on lean, unshifted tail gas. Since the methanol synthesis reaction proceeds at a 2/1 ratio of H_2/CO, the unreacted tail gas (mostly CO) can be burned in the turbine with steam bottoming. The emissions aspects are similar to those of other IGCC systems (see gasification description), however, since cold cleanup systems must be used to eliminate essentially all sulfur, nitrogen and particulate matter which will poison the synthesis catalyst, the tail gas being fired to the combustor is also free of these compounds and the exhaust gases from the turbine/boiler will be low in NOx (below NSPS) and also sulfur and particulate free. The stored methanol can be burned for peaking or can be sold for transportation fuel applications. Methanol combustion in turbines has been used by utilities and is very low in NOx emissions and is, of course, free of sulfur and ash.

Chapter 3: METHODOLOGY

The basic methodology for the quantitative portion of this analysis consisted of the following steps:

- Calculating baseline emissions of conventional technologies for new and existing sources in 2010.
- Calculating emissions from commercialized versions of the proposed technonogies, using emission and market penetration data in Appendix K of the proposals.
- Calculating differentials between the baseline and the proposed technologies, and comparing these to total regional and national emissions for perspective.

Baseline emissions

As noted earlier, this is a comparative analysis, in which emissions from proposed technologies are compared to a baseline emission scenario. Baseline manmade emissions were calculated for 1985 and for the year 2010 for all major economic sectors, including powerplants, industrial boilers, industrial processes, residential and commercial fuel use, and transportation. Certain key industrial subsectors, for which proposals were anticipated, were also evaluated. These calculations were an extension of work performed by DOE and ANL to analyse the environmental impacts of the fifth National Energy Policy Plan (NEP-5). However, the NEP work was at a national aggregate level and lacked detail in some economic subsectors. The disaggregation was conducted by ANL and resulting data were provided to DOE on flexible magnetic disks. Because of the magnitude of the project the original ten federal regions were then aggregated to four quadrants. The quadrants are:

- Northeast (NE) - Federal regions 1, 2, 3, 5, 7
- Southeast (SE) - Federal region 4
- Northwest (NW) - Federal regions 8, 10
- Southwest (SW) - Federal regions 6, 9.

A map of these four regions is presented in Figure 3-1. A summary of baseline emissions is provided in Table 3-0. A more disaggregated version of these baseline data, along with limited documentation, is available in the DOE reading room (Forrestal building, Washington, DC, CCT PON docket).

The pollutants quantified for baseline conditions were selected based on DOE's perception of the most important energy related environmental issues, as discussed in Chapter 1. The pollutants are:

- Air - Particulate matter, sulfur dioxide, nitrogen oxides
- Water - Total suspended solids, and total water consumption
- Solid wastes - Scrubber sludge, ash, other non-hazardous wastes, and hazardous wastes. Changes in these emissions were calculated separately and reported in Tables 3.1 and 3.2 as non-hazardous wastes and hazardous wastes.

Proposed technology emissions

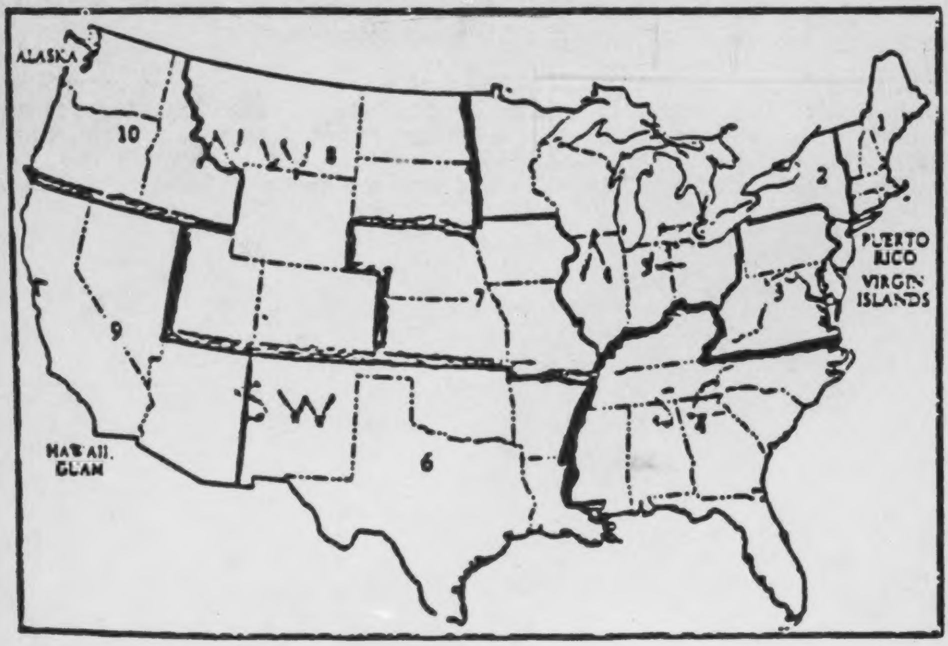
Annual emissions were calculated for each of the above pollutants, based on the material contained on the PON Appendix K form, as completed by the proposer. This form contained not only emission rates, but also the expected market for the technology. Hence, a technology with a large market offered greater potential for significant emission changes. In some cases, the Appendix K data were not within a reasonable range, or were simply not provided. In these cases, DOE attempted to obtain relevant data from the proposal, or assumed reasonable data. These adjustments to Appendix K data are documented in the narrative sheet on each technology, in Chapter 4. Several of the proposals were of such a limited scale that the regional environmental impact was deemed negligible, and the impact was not further quantified.

Calculation of emission changes

The calculation of emission changes for each technology was relatively straightforward, once the annual baseline emissions and the annual emissions for a given technology were established. To make the significance of the absolute changes in emissions more obvious, however, they were converted to percent changes, relative to total emissions of a particular pollutant in the year 2010. Changes caused by retrofit technologies were calculated separately from changes caused by technologies applied to new sources (some proposals applied to both groups). It should be noted that the baseline assumed existing regulations, so proposals which projected a large market predicated on additional regulatory requirements (due to acid rain legislation or revised air quality standards, for example) often received large "credits" for emission reductions of a pollutant (generally SO2). An alternative way of viewing these technologies (which was not chosen) would be to assume that some other baseline technology would have accomplished the same reduction, had the assumed regulation been adopted, so that the only real emission change would have been in collateral pollutants, such as solid wastes, which would accompany the technology change. One must be aware of this baseline convention regarding retrofit technologies in order to appreciate the likely impact of the technologies.

A tabular summary of the percent change in emissions of new and retrofit technologies is provided in Chapter 4. That chapter also contains a more lengthy narrative which expresses necessary assumptions made to facilitate calculations for each technology, and a qualitative discussion of the environmental impacts of the emissions from the commercialized technology.

FIGURE 3-1 THE FOUR QUADRANTS VS.
THE TEN REGIONS OF THE
U. S. ENVIRONMENTAL PROTECTION AGENCY


ALASKA
10
NW
8
1
2
PUERTO RICO
VIRGIN ISLANDS
5
3
7
9
SW
6
4
HAWAII, GUAM

SOURCE U. S Environmental Protection Agency.

Table 3-0: BASELINE EMISSIONS IN THE YEAR 2010

REGION	PM	SO2	NOx	NON-HAZ WASTE	HAZ WASTE	TSS	WATER CONSMN
NE	3.52	13.10	9.19	171.13	86.71	1.20	37381
SE	1.41	5.90	4.25	69.20	36.63	0.48	11243
NW	0.54	1.22	1.69	14.01	5.96	0.17	42916
SW	1.70	5.72	5.60	101.15	75.16	0.55	77109
US	7.16	25.94	20.73	355.49	204.45	2.40	168648

Baseline emission notes:

- o Units are millions of tons per year.
- o Includes manmade emissions from all sectors (utility, transportation, etc.).

PRE-SELECTION ENVIRONMENTAL IMPACT ANALYSIS

Attached are site-specific environmental impact analyses of the proposals submitted in response to the Program Opportunity Notice (PON) for Clean Coal Technology Demonstration Projects, dated February 17, 1986. These analyses are in accordance with the requirements of Section III paragraphs 27, National Environmental Act (NEPA) Strategy, and 27.2, Pre-Selection Project Specifics Environmental Review.

Each analysis includes, to the maximum extent possible:

- A discussion of alternative sites and/or processes reasonably available to the offeror,
- A discussion of the environmental impacts of the proposal,
- Practicable mitigating measures,
- A list of permits, to the extent known, which must be obtained to implement the proposal, and
- A summary of the strengths and weaknesses of the proposal against the environmental criteria for the specific project.

Department of Energy
Washington, DC 20585

AUG 4 1986

DECISION AND ORDER
OF THE DEPARTMENT OF ENERGY

APPEAL

Name of Petitioner: Natural Resources Defense Council

Date of Filing: July 16, 1986

Case Number: KFA-0045
FOIA REQUEST NO. 860602012

On July 16, 1986, the Natural Resources Defense Council (NRDC) filed an Appeal from a determination issued to the organization by the Freedom of Information Authorizing Official of the Office of Procurement Operations of the Department of Energy (DOE). The determination denied a request for information filed by NRDC on May 30, 1986, under the Freedom of Information Act, 5 U.S.C. § 552 (FOIA), as implemented by the DOE in 10 C.F.R. Part 1004. In its Appeal, the NRDC requests that we order the Authorizing Official to release the documents withheld in his June 13, 1986 determination.

The FOIA requires that documents held by federal agencies generally be released to the public upon request. The FOIA, however, lists nine exemptions that set forth the types of information that may be withheld at the discretion of an agency. Those nine exemptions are repeated in the DOE regulations implementing the FOIA. 10 C.F.R. § 1004.10(b). The DOE regulations further provide that a document exempt from mandatory disclosure under the FOIA shall nonetheless be released to the public, unless the DOE determines that disclosure is contrary to federal law or the public interest. 10 C.F.R. § 1004.1.

In its request, NRDC sought certain information contained in proposals submitted to the DOE in response to the Program Opportunity Notice (PON) for the Clean Coal Technology Program, issued February 17, 1986 (DE-PS01-86FE60966). Pursuant to the PON, the DOE solicited proposals for financial assistance required to conduct cost-shared clean coal technology demonstration projects that will lead directly to accelerated commercial availability of these emerging technologies. In his June 13, 1986, determination, the Authorizing Official stated that proposals that have passed preliminary evaluation were being evaluated currently by the Source Evaluation Board, and projects would be selected for award no later than August 1, 1986.

On July 25, 1986, nine firms were selected for potential awards. Thirteen other firms not selected were informed that their proposals may be reconsidered if agreements are not reached with the nine firms initially selected. The chosen proposals are now being transferred to the Morgantown and Pittsburgh Energy Technology Centers for fact-finding, preparation of pre-negotiation positions, and negotiation of the agreements. After this process is complete, and prior to actual award, the cooperative agreements will be submitted to Congress for review.

The Authorizing Official denied the NRDC's request stating that the information was being withheld pursuant to Exemption 4, which protects from mandatory disclosure matters that are "trade secrets and commercial or financial information obtained from a person and privileged or confidential." 5 U.S.C. § 552(b)(4); 10 C.F.R. § 1004.10(b)(4). The Authorizing Official stated that all parts of the proposals, which were submitted in response to a competitive solicitation, are exempt from disclosure pursuant to Exemption 4 because disclosure of information from proposals prior to award would allow a competitor to obtain information concerning a pending proposal and use that information to improve its own proposal in this and possible future solicitations. On this basis, the Authorizing Official concluded that such disclosures could cause substantial harm to the competitive position of the person whose proposal information was disclosed prior to award, and could undermine the government procurement process by impairing the government's ability to obtain proposals in response to future competitive solicitations.

In its Appeal, NRDC argues that the information requested is neither financial nor commercial because it would not identify the person or firm submitting the proposal, or the type of technology, and therefore would have no commercial application. The NRDC also asserts that disclosure prior to an award would not allow a competitor to improve its proposal because competitors would not be authorized to submit improved proposals after the closing date of the PON, which was April 18, 1986. Finally, the NRDC argues that even if the information were arguably exempt from disclosure under the FOIA, it should be disclosed because it is in the public interest to do so, and the Trade Secrets Act, 18 U.S.C. § 1905, does not bar its release.

We have previously held that all parts of a proposal submitted in response to requests for proposals, which are analogous to the PON in this case, are confidential prior to selection of a proposal for negotiation of a contract. McKenna, Conner & Cuneo, 11 DOE ¶ 80,138 at 80,638 (1983) (McKenna); American Bell, Inc., 11 DOE ¶ 80,119 at 80,573 (1983); PRC Energy Analysis Co., 4 DOE ¶ 80,204 at 81,005 (1979). We have also held that such proposals are confidential subsequent to selection of a firm for contract negotiations, but prior to contract award. McKenna, at 80,638. Disclosure prior to the award of a contract or cooperative agreement would allow a competitor to obtain information to improve its own proposal, which might cause substantial harm to the competitive position of the firm whose proposal was released. In the event that contract negotiations fail to produce a final agreement, competitors would have an advantage over those whose proposals were released to the public. Id., at 80,639. This situation could impair the government's ability to obtain future proposals. Accordingly, we have held that until a final contract is awarded entire proposals are exempt from disclosure. Id.

In this case, the initial selection process has begun, but there are many steps to be taken before final cooperative agreements are awarded. Nine proposals have been selected for potential awards and are now being transferred to Energy Technology Centers for fact-finding, then negotiation and preparation of agreements. Congress will then have thirty days to review the cooperative agreements prior to any award. Therefore, the proposals fall within the limits of Exemption 4 of the FOIA.

We note that the fact that material requested pursuant to the FOIA falls within a statutory exemption does not necessarily preclude release of the material to the requester. The DOE regulations implementing FOIA provide, "To the extent permitted by other laws, the DOE will make available records which it is authorized to withhold under 5 U.S.C. § 552 unless it determines that such disclosure is not in the public interest." 10 C.F.R. § 1004.1. Thus, the fact that one of the statutory exemptions may apply to requested material means that the material is exempt from mandatory disclosure. Generally, unless the DOE also determines that disclosure of the material is not in the public interest, it must release the material, insofar as such release is permitted by other laws. McKenna, at 80,650; Miller & Chevalier, 3 DOE ¶ 80,103 at 80,511 (1979).

In Exemption 4 cases, however, we do not make the usual inquiry into the possible public interest in release of material determined to be exempt from mandatory disclosure. Disclosure of confidential or proprietary data that can be withheld pursuant to Exemption 4 would constitute a violation of the Trade Secrets Act, 18 U.S.C. § 1905, unless its release is otherwise authorized by law. 1/ We are unaware of any law which constitutes an

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1/ Exemption 4 of the FOIA, repeated at 10 C.F.R. § 1004.10(b)(4) of the DOE regulations, exempts from

(cont'd)

authorization for the release of information falling within Section 1905. Thus, release of Exemption 4 material is prohibited. McKenna at 80,650; Federal Information Tools, 3 DOE ¶ 80,163 (1979). We therefore conclude that the material we have held is exempt from disclosure pursuant to Exemption 4 cannot be released in the public interest. Accordingly, NRDC's appeal will be denied.

(cont'd)

mandatory disclosure "trade secrets and commercial or financial information obtained from a person and privileged or confidential." Section 1905 makes it a criminal offense for a federal employee to disclose information which "concerns or relates to the trade secrets, processes, operations, style of work, or apparatus, or the identity, confidential statistical data, amount or source of any income, profits, losses, or expenditures of any person, firm, partnership, corporation, or association . . . ." In Chrysler Corp. v. Brown, 441 U.S. 281 (1979), the Supreme Court declined to determine "the relative ambits of Exemption 4 and § 1905," but stated:

> Although there is a theoretical possibility that material might be outside Exemption 4 yet within the substantive provisions of § 1905, and that therefore the FOIA might provide the necessary "authoriz[ation] by law" for purposes of § 1905, that possibility is at most of limited practical significance in view of the similarity of language between Exemption 4 and the substantive provisions of § 1905.

Id., at 319 n.49. We agree with the courts that have held Section 1905 and Exemption 4 to be co-extensive. General Motors Corp. v. Marshall, 654 F.2d 294, 297 (4th Cir. 1981); AT&T Information v. General Services Administration, 627 F. Supp. 1396, 1401 (D.D.C. 1986); Canal Refining Co. v. Corrallo, 616 F. Supp. 1035, 1042 (D.D.C. 1985); J.H. Lawrence Co. v. Smith, 545 F. Supp. 421 (D. Md. 1982). See also 9 to 5 Organization v. Board of Governors, 721 F.2d 1 (1st Cir. 1983)(If documents are not within Exemption 4, disclosure will not violate Section 1905). Accordingly, Section 1905 prevents the release of the PON information sought in this case.

It Is Therefore Ordered That:

(1) The Appeal filed by Natural Resources Defense Council is denied in all respects.

(2) This is a final order of the Department of Energy of which any aggrieved party may seek judicial review pursuant to the provisions of 5 U.S.C. § 552(a)(4)(B). Judicial review may be sought either in the district court in which the requester resides or has a principal place of business or in which agency records are situated or in the District of Columbia.

George B. Breznay
Director
Office of Hearings and Appeals

Date:
AUG 4 1986

Department of Energy
Washington, DC 20585

JAN 22 1987

DECISION AND ORDER
OF THE DEPARTMENT OF ENERGY

Appeal

Name of Petitioner: Natural Resources Defense Council

Date of Filing: December 22, 1986

Case Number: KFA-0069

On December 22, 1986, the Natural Resources Defense Council (NRDC) filed an Appeal from a determination issued to it by the Freedom of Information Authorizing Official of the Office of the Assistant Secretary for Fossil Energy of the Department of Energy (DOE). The determination denied a request for information filed by the NRDC on August 6, 1986, under the Freedom of Information Act, 5 U.S.C. § 552 (FOIA), as implemented by the DOE in 10 C.F.R. Part 1004. In its Appeal, the NRDC requests that we order the Authorizing Official to release the documents withheld in his November 18, 1986 determination.

The FOIA requires that documents held by federal agencies generally be released to the public upon request. The FOIA however, lists nine exemptions that set forth the types of information which may be withheld at the discretion of an agency. 5 U.S.C. § 552(b); 10 C.F.R. § 1004.10(b). The DOE regulations further provide that a document exempt under the FOIA shall nonetheless be released to the public, unless the DOE determines that disclosure is contrary to federal law or the public interest. 10 C.F.R. § 1004.1.

I. BACKGROUND

In its request, NRDC sought the "Pre-Selection Programmatic Environmental Impact Analysis" and the "Pre-Selection Project-Specific Environmental Review," two internal DOE reports which were generated under the Clean Coal Technology Program. The Clean Coal Technology Program is designed to provide financial assistance to qualifying clean coal technology demonstration projects, leading to accelerated commercial availability of these emerging technologies. On February 17, 1986, the DOE issued a Program Opportunity Notice (PON), DE-PSOI-86FE60966, soliciting proposed projects for funding under the program. The information received from each firm pursuant to the PON generally contains a project description, and projections as to market penetrations of the proposed technology and pollutant emission rates or emission reduction potentials for each market subsector identified. The "Pre-Selection Programmatic Environmental Impact Analysis" and "Pre-Selection Project-Specific Environmental Review" sought by NRDC summarize information provided by firms submitting proposals, along with analysis provided by the Program Source Evaluation Board to aid the Source Selection Official in evaluating and ultimately awarding funding to projects. Some projects submitted pursuant to the PON have now been selected for award and negotiations leading to cooperative agreements are currently in progress. Other proposals, not chosen initially, may be selected if agreements cannot be reached with those originally selected.

In his November 18, 1986 determination, the Authorizing Official withheld the portions of the documents which contained brief descriptions of each proposal, and evaluations of the strengths and weaknesses of the project based on environmental criteria, pursuant to Exemptions 4 and 5 of the FOIA. 5 U.S.C. §§ 552(b)(4)-(b)(5); 10 C.F.R. §§ 1004.10(b)(4)-(b)(5). Exemption 4 protects mandatory disclosure of confidential commercial information, while Exemption 5 shields predecisional, deliberative internal agency communications. The NRDC's Appeal challenges the Authorizing Official's determination that some of the requested documents fall under Exemptions 4 and 5 of the FOIA.

In its Appeal, the NRDC argues that the reading given Exemptions 4 and 5 in the present case is broad and improper. In addition, the NRDC contends that the use of both Exemptions 4 and 5 for the same documents renders Exemption 4 invalid, so that consideration need only be given to Exemption 5. The NRDC asserts that the use of Exemption 5 is inappropriate because the withheld information is essentially comprised of environmental analysis and the failure to release it contravenes the National Environmental Policy Act (NEPA), 42 U.S.C. §§ 4371 et seq., which is designed to ensure and facilitate open decisionmaking and public dialogue on matters of environmental concern. Following this reasoning, the group maintains that if the information is factual in nature, then the NEPA regulations on public access to environmental impact statements, 40 C.F.R. § 1505.6(f), would mandate the release of the information regardless of Exemption 5. Finally, the NRDC contends that DOE must disclose the information, regardless of the applicability of the exemptions, if disclosure is in the public interest.

II. ANALYSIS

A. Exemption 4

Exemption 4 permits an agency to withhold from public disclosure "trade secrets and commercial or financial information obtained from a person and privileged or confidential." 5 U.S.C. §

552(b)(4); 10 C.F.R. § 1004.10(b)(4). In order to be exempt from mandatory disclosure under Exemption 4, a document must: (i) contain either trade secrets or "commercial" or "financial" information, (ii) be "obtained from a person," and (iii) contain either "privileged or confidential" information. National Parks & Conservation Ass'n v. Morton, 498 F.2d 765 (D.C. Cir. 1974). If only portions of a document are exempt from disclosure pursuant to Exemption 4, those portions should be deleted, if practicable, and the remainder of the document released. 10 C.F.R. § 1004.10(c). See, e.g., Steptoe & Johnson, 4 DOE ¶ 80,171 (1979).

Commercial or financial information is "confidential" for the purposes of Exemption 4 of the FOIA if the disclosure is likely either to: (i) impair the Government's ability to obtain necessary information in the future, or (ii) cause substantial harm to the competitive position of the person from whom the information was obtained. National Parks, 498 F.2d at 770. DOE regulations provide four additional criteria to be considered when determining whether information is exempt from mandatory disclosure pursuant to Exemption 4: (1) whether the information has been held in confidence by the person to whom it pertains; (2) whether the information is of a type customarily held in confidence by the person to whom it pertains; (3) whether the information was transmitted to and received by the Department in confidence; and (4) whether the information is available in public sources. 10 C.F.R. § 1004.11(f).

We have held on numerous occasions that contract proposals submitted in response to agency solicitations, similar to the PON in this case, are confidential prior to selection of a proposal for negotiation of a contract. McKenna, Conner & Cuneo, 11 DOE ¶ 80,138 at 80,638 (1983) (McKenna); American Bell, Inc., 11 DOE ¶ 80,119 at 80,573 (1983); PRC Energy Analysis Co., 4 DOE ¶ 80,024 at 81,005 (1979). We have also held that such proposals are confidential subsequent to selection of a firm for contract negotiations, but prior to contract award. McKenna, at 80,638. Disclosure prior to the award of a contract or cooperative agreement would allow a competitor to obtain information to improve its own proposal in the present and in future solicitations. This would cause substantial harm to the competitive position of the firm whose proposal was released. Moreover, in the event that contract negotiations fail to produce a final agreement, competitors not initially selected would have an advantage over those firms whose proposals were released to the public. Id. at 80,639. This situation would impair the government's ability to obtain future proposals. Firms would be reluctant to submit proposals to the government if their sensitive commercial or financial information would not be held in confidence. Accordingly, we have held that until a final contract is awarded, entire proposals are exempt from disclosure. Id.

These principles apply with equal validity in the present instance in regard to the descriptions of proposals submitted by firms pursuant to the PON. The submitting firms have a proprietary interest in the innovative clean coal technology projects which they formulated and public disclosure would have an adverse impact upon their competitive positions. Firms would be reluctant to submit proposals for research and demonstration projects if they knew they could be disclosed prior to award and used by their competitors in subsequent submissions. Firms would be unwilling to submit proposals to the government if commercial or financial information would not be held in confidence. The government's ability to obtain this type of information would thus be impaired. Burt A. Braverman, 15 DOE ¶ _____, KFA-0067 (Jan. 9, 1987).

Accordingly, we have concluded that the authorizing official was correct in determining that certain withheld portions of the two reports consist of confidential commercial or financial information which is not subject to disclosure pursuant to Exemption 4 of the FOIA. For the same reasons, the withheld portions of the reports fall within Exemption 4 under the criteria described in section 1004.11(f) of the DOE FOIA regulations.

B. Exemption 5

The Authorizing Official also properly withheld portions of the "Pre-Selection Programmatic Environmental Impact Analysis" and "Pre-Selection Project-Specific Environmental Review" under Exemption 5. Exemption 5 protects "inter-agency or intra-agency memorandums or letters which would not be available to a party other than an agency in litigation with the agency." 5 U.S.C. § 552(b)(5); 10 C.F.R. § 1004.10(b)(5). Exemption 5 is generally recognized as encompassing three distinct privileges: the attorney-client privilege, the attorney work-product privilege and the governmental deliberative process privilege. See, e.g., Coastal States Gas Corp. v. DOE, 617 F.2d 854 (D.C. Cir. 1980) (Coastal States). In the present case, the Appellant challenges the Authorizing Official's reliance on the deliberative process privilege element of Exemption 5.

We have consistently held that the deliberative process privilege shields from public disclosure records reflecting the predecisional consultative process of an agency. Darci L. Rock, 13 DOE ¶ 80,111 (1981); Texaco, Inc., 1 DOE ¶ 80,242 (1978) (Texaco). The deliberative process privilege has been described as the "'privilege for confidential intra-agency advisory opinions' disclosure of which 'would be injurious to the consultative functions of government.'" NLRB v. Sears, Roebuck & Co., 421 U.S. 132, 149 (1975) citing Kaiser Aluminum & Chemical Corp. v. United States, 157 F. Supp. 939, 946 (Ct. Cl. 1958). As this description suggests, not all inter-agency or intra-agency memoranda come within the scope of the deliberative process privilege of Exemption 5. Rather, only deliberative, pre-decisional inter- or intra-agency memoranda are protected from disclosure by Exemption 5. Industrial Sprinkler Co., 12 DOE ¶ 80,111 (1984); Texaco at 81,259; New England Power Co., 5 FEA ¶ 80,616 (1977). However, predecisional materials are not exempt merely because they are prepared prior to a final action, policy or interpretation. These materials must also be a part of the agency's deliberative process by which decisions are made. Vaughn v. Rosen, 523 F.2d 1136, 1144 (D.C. Cir. 1975).

Exemption 5 protects from disclosure materials such as notes and memoranda which contain an employee's opinion, analysis or recommendation concerning possible DOE actions, as well as draft documents, proposals, suggestions, and other subjective documents that reflect personal opinions of the writer rather than the policy of the agency. Coastal States at 866. The factors that should be considered to determine whether a document is protected by the deliberative process privilege include: (i) whether the document is "predecisional" (i.e. whether it was generated before the adoption of an agency policy); (ii) whether the document is "deliberative" (i.e. whether it reflects the give-and-take of consultative process); (iii) whether the document is so candid or personal in nature that public disclosure would stifle honest and frank communication in the future; and (iv) whether the document is recommendatory in nature or is a draft of what will become a final document. Id.

In the present case, we find that the Authorizing Official was correct in his determination that some of the information in the withheld portions of the documents falls within the scope of the deliberative process privilege of Exemption 5 and is not subject to mandatory disclosure under the FOIA. The Official stated that the information deleted from the documents under Exemption 5 consists of evaluation comments which discuss the strengths and weaknesses of each proposed project. Letter at 3. The Official also stated that the views expressed were not final agency opinion, but rather were used simply as an aid to the Source Selection Official. Id. Our review of the withheld information confirms these statements. The information withheld was a part of the pre-decisional deliberative process protected by Exemption 5. The release of such pre-decisional comments would stifle the free flow of information needed to make informed agency decisions.

The Authorizing Official was also correct in his finding that Exemption 5 of the FOIA is not preempted by the NEPA in the present proceeding. While the NEPA process was designed to facilitate public involvement and an open dialogue on matters of environmental concern, it has no provisions that directly conflict or override the provisions of the FOIA with regard to the type of information in the present appeal. NRDC makes reference to 40 C.F.R. § 1506.6(f) which requires that environmental impact statements (EIS) be released to the public pursuant to the provisions of the FOIA without regard to the exclusions for inter-agency memoranda where such memoranda contain comments of the federal agencies concerning the environmental impact of the proposed action. However, the EIS process has not yet begun. The agency's summary report on emissions projections, which is what is involved here, does not constitute a formal EIS within the meaning of section 1506.6(f). Rather, the information withheld under Exemption 5 is simply an internal assessment of environmental concerns, which is preliminary in nature. The agency will not know which projects will require a full-blown EIS until projects have been selected and cooperative agreements are executed. Only when the final selections are completed will the formal environmental impact statement process for those projects begin. Therefore, the Authorizing Official properly withheld the preliminary environmental information in the reports pursuant to Exemption 5.

C. Public Interest in Disclosure

The fact that the information which the Appellant seeks falls within statutory exemptions does not necessarily preclude release of the material. DOE regulations provide that documents exempt from mandatory disclosure under the FOIA shall be released, regardless of their exempt status, unless the DOE determines that disclosure is contrary to the federal laws or to the public interest. 10 C.F.R. § 1004.1. Thus, a finding that one of the statutory exemptions applies to the requested material merely means that the material is exempt from mandatory disclosure. Unless the DOE determines that disclosure is not in the public interest, it must release the material insofar as such release is permitted by other laws. Miller & Chevalier, 3 DOE ¶ 80,103 (1979).

In the present case, the release of the material withheld pursuant to Exemption 5 would have a chilling effect upon the ability and willingness of DOE employees to make open and honest recommendations. This would deprive the agency of the benefit of employees' open and candid opinions, and stifle the exchange of the free ideas and opinions necessary for sound decisionmaking. The give-and-take of the deliberative process is necessary to develop sound policy decisions. This type of frank communication would be jeopardized if the type of evaluative comments in the reports were subject to disclosure prior to the agency announcing its policy. In addition, the release of the proprietary commercial and financial material exempt from disclosure pursuant to exemption 4 would violate the Trade Secrets Act, 18 U.S.C. § 1905, since no other law authorizes release of the information. Accordingly, it would not be in the public interest to disclose the withheld portions of the documents.

It Is Therefore Ordered That:

(1) The Appeal filed by Natural Resources Defense Council on December 22, 1986 is hereby denied.

(2) This is a final order of the Department of Energy of which any aggrieved party may seek judicial review pursuant to the provisions of 5 U.S.C. § 552(a)(4)(B). Judicial review may be sought in the district in which the requester resides or has a principle place of business, or in which the agency records are situated, or in the District of Columbia.

George B. Breznay
Director
Office of Hearings and Appeals

Date:
JAN 2 2 1987

PETC 1321.1
(5-83)

United States Government **Department of Energy**

memorandum

DATE: JUN 2 1987

REPLY TO
ATTN OF: FE-1 (J. A. Wampler)

SUBJECT: Memo-to-File (MTF) and Final NEPA Determination for the Babcock and Wilcox Company Demonstration Project Under the Clean Coal Technology (CCT) Program

TO: Memo-to-File

The Department of Energy is proposing to enter into a Cooperative Agreement with Babcock and Wilcox Company of Barberton, Ohio. The primary objective of this Cooperative Agreement is to conduct a cost-shared clean coal technology project entitled "LIMB Demonstration Project Extension." The proposed project is to extend testing of the Limestone Injection Multi-stage Burner (LIMB) project, which is currently being performed under contract to the U.S. Environmental Protection Agency (EPA).

The EPA LIMB project has undergone an environmental review in accordance with EPA Regulations on Implementation of NEPA Procedures (40 CFR 6.704 (b) (2)) which resulted in EPA Form 5300-23 being issued as a Finding of No Significant Impact (FNSI).

The Pittsburgh Energy Technology Center has prepared this Memo-to-File (MTF), for the Department of Energy, to comply with the requirements of the National Environmental Policy Act (NEPA). The summary information contained in this MTF is based upon a review of the documentation presented in the technical proposal submitted by Babcock and Wilcox in response to the CCT Program Opportunity Notice, a visit and inspection of the proposed project site, and the volume of environmental information submitted by Babcock and Wilcox Company.

NEPA DETERMINATION

It is my determination as the Assistant Secretary for Fossil Energy that the information available is adequate and sufficient to show that the Babcock and Wilcox Company demonstration project clearly does not constitute a major federal action significantly affecting the quality of the human environment. Therefore, this MTF is sufficient to satisfy DOE's NEPA compliance obligation and neither an Environmental Assessment (EA) nor an Environmental Impact Statement (EIS) is required. My determination is based on the finding that impacts will be either nonexistent (e.g , no major construction), or negligible because of the magnitude of the impact or through mitigating actions (e.g., air quality impacts, water quality impacts, solid wastes).

A copy of this memorandum will be forwarded to the Office of NEPA Project Assistance, Assistant Secretary for Environment, Safety, and Health. This will complete the Office of Fossil Energy's responsibility in complying with the DOE NEPA guidelines for this action.

The remainder of this MTF contains the following: (1) Description of the Proposed Project, (2) Description of the Project Location, (3) Alternatives to the Proposed Action, (4) Potential Issues, and (5) Conclusion.

DESCRIPTION OF PROPOSED PROJECT

This proposed project is to extend testing of the LIMB project, which is currently being performed under an EPA contract. The objectives of the project are to demonstrate that: (1) significant reduction of SOx and NOx emissions can be achieved at a fraction of the cost of add-on wet flue gas desulfurization systems; (2) boiler reliability, operability and steam production can be maintained at levels existing prior to retrofit of the LIMB system; and, (3) technical difficulties attributable to LIMB operation can be resolved in a cost-effective manner. In addition, DOE proposes to fund an alternative technology termed Coolside to demonstrate that this process is a viable method for reducing sulfur dioxide by injecting sorbent and water into the flue gas ductwork downstream of the boiler. Both technologies require particulate removal equipment to cleanse the flue gas of the normal ash component and the additional sorbent. This consideration was primary in the selection of the Edgewater Unit No. 4 as the host site because of the large excess capacity of the existing electrostatic precipitator (ESP).

The DOE portion of the project will be conducted over 43 months, during which an 18-month period will be used for testing (14 months for the LIMB extension and 4 months for the Coolside demonstration). The EPA Base LIMB project is currently under way and the testing portion which will begin in June 1987 has a duration of 12 months. The DOE funded project will follow the Base LIMB project and involves minimal construction since 90% or more of the required facilities will have been constructed for the Base project. Some minor construction will be required for the Coolside duct injection portion of the project.

The LIMB project sponsored by EPA will utilize one type of coal and one sorbent. The DOE funded LIMB extension will test three different coals (1.5 percent, 3 percent, and 3.8 percent sulfur content) and four different sorbents (calcitic limestone, dolomitic limestone, dolomitic hydrated lime, and promoted lime). The Coolside process will be evaluated using a 3 percent sulfur coal and calcitic hydrated lime combination.

Total projected raw material requirements for the LIMB extension and Coolside demonstration are summarized below:

LIMB Extension:

1.5% S Coal	60,000 tons
3.0% S Coal	60,000 tons
3.8% S Coal	60,000 tons

Calcitic Limestone	9,000 tons
Dolomitic Limestone	16,000 tons
Dolomitic Hydrated Lime	8,000 tons
Promoted Lime	2,500 tons

Coolside Demonstration:

3.0% S Coal	60,000 tons
Hydrated Calcitic Lime	6,000 tons
50% NaOH Solution	1,200 tons

DESCRIPTION OF PROJECT LOCATION

The project will be performed at the Ohio Edison Company Edgewater Station. The Edgewater Station is located in northeastern Ohio in Lorain County at 200 Oberlin Avenue, Lorain, Ohio. The station is located adjacent to Lake Erie, approximately 25 miles west of Cleveland and 90 miles east of Toledo, Ohio.

The facility has a total net demonstrated capability of 214 MWe and consists of three pulverized coal-fired boilers, two electric generating turbines, and two oil-fired combustion turbine generators. Edgewater Unit No. 4, the boiler to be used for the DOE project, has a rated capacity of 105 MWe and is presently burning eastern bituminous coal with a 1.5 to 1.7 percent sulfur content. The boiler can consume 42.5 tons of coal per hour. Total station consumption with all units operating is 1,400 tons per day.

Coal is delivered by 45 to 50 trucks per day. Unit No. 4 is equipped with a new oversized Lodge-Cottrell Electrostatic Precipitator (ESP). The facility utilizes 110 million gallons per day (MGPD) of once-through cooling water taken from and returned to Lake Erie and discharges 1.1 MGPD of "low-volume" wastewater. Fly ash and bottom ash are trucked to a 56-acre landfill in Lorain County.

The station is located in Lorain and occupies 21 acres on a man-made promontory or peninsula on the lake shore at the mouth of Black River. The facility is bounded to the northeast by a filtration plant and railroad spur and to the south and southwest by residential areas. The station has been in operation since 1919.

Existing Air Quality

The Edgewater plant is located in an area designated attainment for SO_2 and non-attainment for secondary total suspended particulate (TSP).

Ecological Conditions

The property is fully developed and, as such, has very little, if any, natural vegetation. The site has very little value as habitat for wildlife because of its previous and existing use as a coal-fired power station.

Socio-Economic Conditions

The population of Lorain County in 1980 was 274,909 up from 256,843 in 1970. The population of the city of Lorain in 1980 was 75,416 down from 78,185 in 1970. The average unemployment in 1981 for Lorain County was 13.3 percent. Lorain

County unemployment in 1984 exceeded 20 percent. Manufacturing plays a major role in Lorain's economy. In 1978, 40,997 people, or 38.6 percent, of the labor force were employed by 55 diversified manufacturing industries in the area. The principal industries in the Lorain area include steel, shipbuilding, and automobiles.

Aesthetic Conditions

The area in the vicinity of the proposed demonstration project is heavily industrialized. As such, there are no especially scenic vistas in this general area. Examples of adjacent operations include a USX steel making plant which is currently shut-down.

ALTERNATIVES TO THE PROPOSED ACTION

No Action Alternative

The goal of the Clean Coal Technology Program is to develop reliable and economical utilization of this country's vast coal reserves, while also improving coal's environmental acceptability. Without this demonstration program, there would be alternatives to using coal in retrofit applications for both utility and industrial boilers; however, the alternatives would be more complicated and more costly. The successful demonstration of LIMB and Coolside technologies will provide lower-cost technologies for simultaneous control of sulfur and nitrogen oxides emissions from existing coal-fired electric power plants.

Alternative Technologies

There are two competing technologies that are presently in commercial operation on coal-fired power plants. They are the wet limestone flue gas desulfurization and spray dryer SO_2 control processes. The existing processes are high in capital cost and require a significant amount of space for installation. By contrast, LIMB and Coolside are characterized by low capital cost and minimal installation space.

Alternate Sites

The proposed DOE LIMB project is an extension of the EPA LIMB project which is already in existence at the Edgewater Station. For this reason no alternate sites were investigated.

POTENTIAL ISSUES

Effects Resulting From Construction

As noted in previous sections, the DOE funded portion of the project will follow the EPA LIMB demonstration which is already under way. EPA has determined that there will be no significant environmental impact from the LIMB project. Since 90 percent or more of the facilities required for the DOE LIMB extension and Coolside demonstrations will have been constructed prior to DOE participation, there are clearly no potentially significant impacts due to construction which would result from the proposed DOE project.

Effects Resulting From Operation

Operation of the LIMB extension and Coolside demonstrations will have both beneficial and adverse effects. Beneficial effects include improvements to local air quality as a result of reduced SOx and NOx emissions at the Edgewater station. Successful demonstration will promote the use of these technologies at other coal-fired power stations which may be required to achieve more stringent emission standards or alternatively to use higher sulfur coals economically that currently require expensive control equipment to meet existing emission limits. Adverse effects include: the generation of a larger quantity of solid waste, the need for increased truck transport of sorbent and additives to the plant and removal of solid waste, and the consumption of sorbent materials.

Each of these effects is discussed below.

1. Air Quality Effects

Operation of the DOE LIMB extension project will result in a net decrease in SOx and NOx emissions. The LIMB technology is expected to be capable of reducing SOx and NOx emissions by 50 percent of uncontrolled levels. Currently the host site is discharging SO_2 at a rate of 2.44 lbs. per million Btu as a result of burning coal with a 1.5 to 1.7 percent sulfur content. Based on the test coal sulfur contents of 1.5, 3.0, and 3.8 percent, the station will emit SO_2 at the rates of 1.17, 2.33, and 2.95 lbs. per million Btu. Overall,the SO_2 emissions will be less than the current rate except for the period when 3.8 percent sulfur coal is used.

The Coolside process is capable of achieving 50 to 80 percent reduction in uncontrolled SO_2 emissions. Overall, based on 3 percent sulfur coal the SO_2 emissions will be up to 48 percent less than the present emissions, if 80 percent SO_2 reduction is achieved.

NOx reduction will be realized by exchanging low-NOx B&W XCL burners for the circular burners currently in service. The predicted emission for the demonstration is 0.48 lbs. of NOx per million Btu. Overall, NOx emissions reduction will vary from 27 to 44 percent depending on boiler load.

Particulate loading to the ESP will increase with the injection of sorbent into the boiler or flue gas. However, the over-design of the ESP provides a large buffering capacity and in combination with the humidification system which enhances precipitator efficiency, will ensure that particulate emissions will be maintained below the 0.1 lbs. per million Btu standard.

2. Surface and Groundwater Impacts

Surface water impacts from operation of the projects will be small compared with the existing impact from the coal-fired station. There are no significant wastewater discharges from LIMB and Coolside in comparison with the Edgewater power plant discharges previously described. The character of the discharges may change due to sorbent infiltration into the sluice water. This could result in a higher effluent pH. A system will be installed to adjust the pH to 7-8 to ensure compliance with effluent limitations. The wastewater generated with LIMB and Coolside technology retrofit to a power plant is not expected to be unique as compared with a conventional coal fired power plant without these retrofit technologies.

3. Solid Waste Disposal

Generation of solid waste consisting of ash, sorbent, additive (in the case of Coolside) and hydration water will be greater than baseline by a factor of 2 to 4 or a 100 to 300 percent increase in solid waste. Over the life of the LIMB extension and Coolside demonstration projects, the total solid waste is estimated at about 30 acre-feet. Based on a typical fill depth of ten feet, waste disposal will require three acres of land. The LIMB and Coolside ash will be segregated in the disposal site to allow for long term observation and testing. Ohio EPA will require a hydrologic study of the solid waste disposal area and installation of monitoring wells to ensure that ground water impacts from solid waste disposal will be clearly insignificant.

4. Ecological Impacts

The demonstration project has no ecological impacts at the Edgewater station since it is an existing power plant and there is no suitable habitat on-site nor sensitive aquatic or terrestrial habitats nearby.

5. Floodplains or Wetlands

The proposed plant site is divided into two fairly level parts by a Lakeshore ridge which rises some 20 feet above the lake shore. Approximately two- thirds of the site is located below the ridge and this portion is about five feet above the normal lake level but no construction will be undertaken in this portion. There are no wetland areas involved.

6. Noise

There will be an insignificant change in noise level in the residential area during construction. Any additional noise that will occur will be behind the existing power plant and some 1000 feet from the noise sensitive area.

7. Land Use Impacts

Land use impacts at the LIMB Extension Facility will be minimal since the demonstration project is taking place at an existing site and very little additional land will be used.

8. Socioeconomic Impacts

Construction of the Demonstration Facility is projected to require approximately 40 workers at peak activity. The construction period for this plant is forecast to be approximately six months. Effects of the added construction workers are expected to be experienced largely in the immediate area. However, the impacts on jobs and the economy will be small and short-lived since the project has a limited duration (43 months).

9. Conflicts with Historic Areas

There are no impacts to sites either listed or eligible for the National Register of Historic Places since the demonstration will be conducted on an already disturbed site.

10. Raw Materials

The total coal consumption of the LIMB and Coolside projects will be 240,000 tons. This consumption, however, will not be greater than current consumption.

The use of sorbents will amount to about 41,500 tons. This quantity is a negligibly small fraction of sorbent availability.

The demonstration will use up to 0.36 MGPD more cooling water and up to 0.14 MGPD more process water. These increases are small in comparison to the station's current requirements of 110 MGPD for cooling and 1.14 MGPD for process purposes. The water source is Lake Erie which is a virtually inexhaustible water supply at these usage levels.

11. Other Effects of Operation

Currently 45 to 50 trucks per day are needed for coal delivery and fly ash removal from the site. An increase of traffic of 20 to 24 trucks per day will be required for delivery of sorbents and sodium hydroxide to the plant and removal of the additional solid waste generated. The increased effects on residential areas are currently and will be in the future minimized by limiting transport operations to normal working hours of the day and only during weekdays.

Permitting Requirements

Ohio Edison Company is in the process of modifying the existing permits for air emissions, wastewater discharge, and solid waste disposal for the EPA LIMB project. Once these permits are obtained from Ohio EPA they will be applicable to the DOE LIMB extension. No additional permits for air, water, or solid waste disposal will be necessary for the DOE demonstration.

CONCLUSION

The information available is adequate and sufficient to show that the LIMB Demonstration Project Extension proposed by Babcock and Wilcox Company clearly does not constitute a major federal action significantly affecting the quality of the human environment. Therefore, neither an Environmental Assessment nor an Environmental Impact Statement is required.

Reference

1. "Environmental Information to Fulfill NEPA Information Requirements for the LIMB Extension and Coolside Demonstration Projects, Edgewater Unit No. 4," Radian Corporation, May 15, 1987.

J. Allen Wampler

J. Allen Wampler
Assistant Secretary
Fossil Energy

DOE F 1325.8
(10-84)

United States Government **Department of Energy**

memorandum

DATE: MAR 26 1987

REPLY TO ATTN OF: FE-1

SUBJECT: Memo-to-File (MTF) and Final NEPA Determination for the Coal Tech Corporation Demonstration Project Under the Clean Coal Technology (CCT) Program

TO: Memo-to-File

The Department of Energy is proposing to enter into a Cooperative Agreement with Coal Tech Corporation of Merion, Pennsylvania. The primary objective of this Cooperative Agreement is to conduct a cost-shared clean coal technology project entitled "Demonstration of an Advanced Cyclone Coal Combustor with Internal Sulfur, Nitrogen, and Ash Control for the conversion of a 23 million Btu per Hour Boiler to Coal."

The Pittsburgh Energy Technology Center has prepared this Memo-to-File (MTF), for the Department of Energy, to comply with the requirements of the National Environmental Policy Act (NEPA). The summary information contained in this MTF is based upon a review of the documentation presented in the technical proposal submitted by Coal Tech in response to the CCT Program Opportunity Notice, a visit and inspection of the proposed project site, and the volume of environmental information submitted by Coal Tech Corporation.

NEPA Determination

It is my determination as the Assistant Secretary of Fossil Energy that the information available is adequate and sufficient to show that the Coal Tech Corporation demonstration project clearly does not constitute a major Federal action significantly affecting the quality of the human environment. Therefore, this MTF is sufficient to satisfy DOE's NEPA compliance obligation and neither an Environmental Assessment (EA) nor an Environmental Impact Statement (EIS) is required. My determination is based on the finding that impacts will be either nonexistent (e.g., no major construction, short project duration), or negligible because of the magnitude of the impact or through mitigating actions (e.g., air quality impacts, water quality impacts, solid wastes).

A copy of this memorandum will be forwarded to the Office of NEPA Project Assistance, Office of the Assistant Secretary for Environment, Safety and Health. This will complete the Office of Fossil Energy's responsibility in complying with the DOE NEPA guidelines for this action.

The remainder of this MTF contains the following: (1) a description of the proposed project, (2) a description of the project location and existing environment, (3) alternatives to the proposed action, (4) potential issues, and (5) conclusion.

Description of Proposed Project

Coal Tech Corporation will test a 30 million Btu per hour coal-fired advanced cyclone combustor which will be installed on an existing boiler that is entirely enclosed within an existing building. The existing boiler is designed for oil- or gas-firing with an input heat capacity of about 23 million Btu/hour. The project will be conducted at the Keeler Boiler Company plant in Williamsport, Pennsylvania, and will be conducted in three distinct phases. Phase I consists primarily of activities involving design and the acquisition of necessary environmental approvals. During Phase II, Coal Tech will install standard equipment for handling and feeding pulverized coal, a conveyor for slag handling, and a scrubber for the removal of particulate matter from the boiler flue gas. After installation of this equipment, Coal Tech will perform a 30 hour shakedown test. During Phase III, long term testing will be conducted. This long term testing will be divided into two periods of 470 and 400 hours each. The overall test program is the combination of shakedown and long term testing for a total of 900 hours. During operation, the coal feed rate will be 1 ton/hour and will operate up to 16 hours per day. Coal will be delivered to the site in 20 ton pneumatic trucks, which will serve as the feed source to the combustor. Deliveries will occur once every 1.5 days, on the average. Limestone will be stored in a small storage silo and will be delivered less frequently. Between specific tests there will be data analysis and reporting. Upon completion of the test program, test equipment will be removed from the test site at Keeler and a final report will be prepared describing the experience with testing the advanced cyclone combustor. The project will have a duration of 25 months.

The current 30 million Btu/hour combustor demonstration is the next logical step in the commercialization of this system. It has been successfully tested at the 1 million Btu/hour and 7 million Btu/hour sizes. The success of this demonstration, a scale-up of 4.3, is intended to be the final step in the commercialization of the system for industrial size boilers. It will also provide an excellent basis for scale-up to the larger, 100 million Btu/hour utility size combustor. The total potential retrofit market for this technology is estimated at 60,000 combustors, including coal, gas, and oil fired boilers. If successful, this project will also make high sulfur U.S. coals more useful and in so doing reduce U.S. dependence on foreign oil.

Description of Project Location

1. General Description of Area

The proposed project will be located at the Keeler Boiler Company facility in Williamsport, Pennsylvania. The City of Williamsport is situated in north-central Pennsylvania and is the largest city in Lycoming County. The population of Williamsport is approximately 33,400 residents and accounts for 28 percent of the total population of Lycoming County.

The City of Williamsport is located approximately 17 miles north of Interstate 80 and can be accessed by State highways which include Routes 15 and 220. The Keeler Boiler Company property is bounded on the south by both Routes 15 and 220 and can be directly accessed without the use of city streets. The City provides all essential services. In particular, water supply and sewage treatment are provided and available on site.

2. **Description of Plant Site**

The Keeler Boiler Company property is fully developed and includes several buildings which house administrative personnel, fabrication operations, and central heating. The proposed project will be located in the existing boiler house which contains two 23 million Btu/hour D tube package boilers and associated controls. These boilers are currently oil fired and are used to provide steam for space heating. One of these boilers will be converted to coal firing by the installation of the Coal Tech Advanced Combustor and associated support equipment. This facility currently has all necessary utilities in place to operate both boilers using oil as fuel.

3. **Existing Air Quality**

Lycoming County is designated by the Pennsylvania Department of Environmental Resources as a Non-Air Basin Area of the state. Lycoming County is presently classified as having attained Secondary National Ambient Air Quality Standards for all Clean Air Act Criteria Pollutants. There are no major emission sources presently located in the County.

Alternatives to the Proposed Action

1. **No Action Alternative**

The goal of the Clean Coal Technology Program is to develop reliable and economical utilization of this country's vast coal reserves, while also improving coal's environmental acceptability. Without this demonstration program, there would be alternatives to using coal in retrofit applications for both utility and industrial boilers; however, the alternatives would be more complicated and more costly. The Coal Tech combustor proposes to reduce SOx, NOx, and particulates in a single unit which is retrofittable to a wide range of existing boilers.

2. **Alternative Technologies**

There are a number of competing technologies, such as other slagging and cyclone combustors, sorbent injection systems, or other flue gas cleanup systems. However, the Coal Tech cyclone's main technical advantage is that it combines the combustion, sulfur and nitrogen oxides control, and high ash retention, in a single device that can be attached to an existing boiler. The key benefit of the cyclone is the low cost of the combustor, relative to the balance of the coal conversion equipment and relative to conventional flue gas cleanup control systems. In addition, with the use of the cyclone, the boiler can operate at its rated capacity, which offers a significant economic advantage to this technology.

3. **Alternate Sites**

The Keeler site was selected based on the availability of a suitably sized boiler, the willingness of Keeler to participate in the project, and the technical knowledge of the Keeler staff.

Potential Issues

1. **Air Quality Impacts**

Air quality impacts due to construction will be negligible due to the insignificant amount of construction associated with this project which are limited to those associated with installation of equipment. Any such impacts will be confined within the site boundary.

Operation of the Advanced Combustor with coal will result in emissions of particulates, SOx, NOx, and CO. The State standards for the area limit both particulate and SOx emissions. Although expected SOx emissions are well below the State limit, particulate emissions approach the State limit and, as such, plans have been developed to include a venturi scrubber to ensure compliance. Total emissions resulting from the testing will be well below the de minimus standard and will not result in any significant impacts on existing air quality.

2. **Water Quality Impacts**

Operations result in the use of 3,600 gallons per hour of city supplied water to cool the combustor, quench and solidify the molten slag, and operate the venturi scrubber.

A combined waste water stream results and this stream will be combined with the main sanitary waste water stream from the Keeler plant and discharged to the Williamsport Sanitary Authority Central Treatment Plant. The effect of this waste water stream has been investigated and has been determined to have a negligible effect on the normal flow of 250,000 to 333,000 gallons per hour to the sanitary plant.

3. **Waste Disposal**

Operation of the combustor results in a quenched slag which, through previous tests, is believed to be inert since all constituents are bound into the slag matrix. The solidified slag produced from the combustion process is generated at a maximum rate of 400 pounds per hour. Offsite disposal will be conducted at a local landfill subject to appropriate permit approvals. The estimated quantities are relatively insignificant when compared to total solid wastes to be landfilled within the county yearly. Neither the quantity nor characteristics of this waste will result in any significant effects.

4. **Ecological Impacts**

This project is located on the Keeler Boiler Company property which is fully developed and includes several buildings that house both administrative personnel and operations activities. Specifically, the project will be located in an existing boiler house. The project will have no ecological impact since it is involved with installation of equipment inside an existing structure.

5. **Floodplains or Wetlands**

The Keeler property is fully developed and there are no wetlands nor impacts on floodplains.

6. **Noise**

The nature of the project is that of short term (900 hours) test program. The operation will be conducted inside an existing boilerhouse on an existing boiler. Keeler operations will not be significantly altered by performance of these tests. The deliveries of coal and limestone will not result in a significant increase in traffic or noise levels.

7. **Land Use and Socioeconomic Impacts**

The land use classification of the site will not change and there is no need for acquisition of additional land.

Construction and operation will use labor available within the primary area. The relatively short construction and operation activities associated with this project result in no discernible socioeconomic impact.

8. **Conflicts with Historic Sites**

None.

9. **Permitting Requirements**

The environmental permit requirements associated with this project will be obtained from the Pennsylvania Department of Environmental Resources. Coal Tech Corporation presently has a variance from the Bureau of Air Quality Control to conduct five one-day tests. A formal plan approval will be obtained to conduct the 900 hour test program.

A permit for solid waste disposal will be obtained from the Bureau of Solid Waste Management. A permit for discharge of waste water to the sanitary sewer will be obtained from the Williamsport Sanitary Authority.

Conclusion

The information available is adequate and sufficient to show that the Advanced Cyclone Combustor Project proposed by Coal Tech Corporation clearly does not constitute a major Federal action significantly affecting the quality of the human environment. Therefore, neither an Environmental Assessment nor an Environmental Impact Statement is required.

Reference

1. "Volume of Environmental Information for the Demonstration of an Advanced Cyclone Coal Combustor with Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23 million Btu/hour Boiler to Coal," Coal Tech Corporation, December 1986.

J. Allen Wampler

J. Allen Wampler
Assistant Secretary
Fossil Energy

DOE F 1325.8
(12-84)

United States Government Department of Energy

memorandum

DATE: MAR 5 1987

REPLY TO
ATTN OF: FE-1

SUBJECT: Memo-To-File (MTF) and Final NEPA Determination for the Tidd PFBC Demonstration Plant Project of the Clean Coal Technology Program

TO: Memo-To-File

The Department of Energy is proposing to enter into a Cooperative Agreement with the Ohio Power Company, a subsidiary of American Electric Power Company, Incorporated (AEP). The primary objective of this Cooperative Agreement is to conduct a cost-shared clean coal technology project which will demonstrate pressurized fluidized-bed combustion (PFBC) combined-cycle technology for use in commercial electric generating plants.

The Morgantown Energy Technology Center has prepared this Memo-To-File (MTF) in accordance with requirements of the National Environmental Policy Act (NEPA). The summary information contained in this MTF is based on the environmental report submitted by AEP, a site visit and environmental survey of the proposed project location, and a review of the technical proposal submitted by AEP in response to the Clean Coal Technology Program Opportunity Notice.

NEPA Determination

It is my determination as the Assistant Secretary of Fossil Energy that, while the proposed action does not qualify for a categorical exclusion under the Department's NEPA guidelines, the information available is adequate and sufficient to show that the Tidd PFBC Demonstration Plant Project clearly does not constitute a major federal action significantly affecting the quality of the human environment. Therefore, neither an Environmental Assessment (EA) nor an Environmental Impact Statement (EIS) is required. My determination is based on the finding that impacts will be either nonexistent (e.g. impacts to floodplains and wetlands, conflicts with historic areas), negligible because of the magnitude of the impact or through mitigating actions (e.g. air quality impacts, water quality impacts, ecological impacts, noise), or beneficial (e.g. socioeconomic impacts).

A copy of this memorandum will be forwarded to the Office of NEPA Project Assistance, Office of the Assistant Secretary for the Environment. This will complete the Office of Fossil Energy's responsibility in complying with the DOE NEPA guidelines for this action.

The remainder of this MTF contains the following: (1) a description of the proposed action, (2) a description of the project location and existing environment, (3) alternatives to the proposed action, (4) potential issues, and (5) conclusion.

Description of Proposed Project

The objective of this project is to engineer, design, and construct a 70-MWe pressurized fluidized-bed combustion (PFBC) combined-cycle demonstration plant at Ohio Power Company's deactivated Tidd Plant near Brilliant, Ohio. In the PFBC process, crushed coal and a sorbent material (dolomite or limestone) are continuously fed into a pressurized vessel in which air fed from the bottom maintains the coal and sorbent in a highly turbulent state, known as fluidization. Electric power is produced by two electric generators, one driven by a gas turbine and the other by a steam turbine. This combined-cycle power generation results in greater thermal efficiency than can be achieved with conventional pulverized-coal fired boilers. In addition, PFBC technology will utilize high sulfur, eastern U. S. coals while still meeting environmental standards.

Achievement of the ultimate goal of commercialization requires the successful operation of a demonstration-scale facility. Operation of the Tidd PFBC plant will provide the necessary information for scale-up of the technology to a commercial-size facility. The proposed demonstration plant will repower Tidd Unit 1, a 110-MWe steam plant. The Tidd plant was retired in 1976 since it was not cost-effective to meet emission regulations. This is significant in that the specific purpose of this project is to demonstrate that combined-cycle PFBC technology is a cost-effective, reliable, and environmentally superior alternative to conventional coal-fired electric power generation with flue gas desulfurization.

Description of the Project Location

1. General Description of the Area

The demonstration plant will be located at the deactivated Tidd Plant, just South of Brilliant, Ohio, in Jefferson County. This area is one of the most heavily industrialized areas in the country, with the Ohio River draining an area of approximately 25,000 square miles. The climate of the region is humid continental. The topography of the area is hilly with ridgetops reaching elevations of 700 feet above the river.

2. Description of the Plant Site

The plant site is on the Ohio River, at River Mile 76.6, approximately ten miles upriver from Wheeling, West Virginia. The existing power complex, including the deactivated Tidd Plant and the adjacent Cardinal Power Plant, extends two miles along the Ohio River and is bordered by a main line of the Norfolk and Western Railroad. The railroad line runs parallel with Ohio Route 7 which runs North-South.

Alternatives to the Proposed Action

1. No Action Alternative

The goal of the Clean Coal Technology Program is to develop reliable and economical utilization of this country's vast coal reserves, while also improving the environmental acceptability. Without the demonstration program, the only option for production of power using coal on a large scale is a conventional pulverized coal-fired plant equipped with flue gas desulfurization (FGD). However, the reliability of the FGD system of such a plant, while firing high sulfur coal (4 percent or greater), is not certain. In addition, the cost of such a system results in high electricity costs. The lower capital costs, higher thermal efficiencies, and environmental advantages of advanced energy technologies such as combined-cycle PFBC cannot be obtained through the no-action alternative.

2. Alternative Technologies

The availability of alternative technologies for either repowering of existing plants or new power plants is limited. In addition to conventional pulverized coal plants, some of the technologies that are close to commercialization include Turbo-Charged PFBC, Integrated Gasification Combined Cycle (IGCC) with cold gas cleanup, and Atmospheric Fluidized-Bed Combustion (AFBC). However, these technologies do not offer the higher thermal efficiencies which are available with PFBC combined-cycle. Other alternatives, such as IGCC with hot gas cleanup and advance retrofit technologies for pollutant removal, will also be demonstrated as part of the Clean Coal Technology Program.

3. Alternative Sites

A number of alternative sites were considered by AEP for the demonstration plant. The sites considered were generally similar in that the sites were existing power complexes located on navigable rivers. The advantages to the chosen site include minimal environmental impact and cost savings associated with use of existing plant equipment.

Potential Issues

1. Air Quality Impacts

Air quality impacts due to construction will be those typical of any construction activity - fugitive dust and exhaust fumes. Fugitive dust impacts will be minimized through a dust suppression program. Impacts due to exhaust fumes will be minimal and primarily confined to the site. Air quality impacts due to plant operations will be similar in nature but lower in quantity to those associated with power generation with conventional pulverized coal-fired technology.

The site area of the proposed plant is designated as a non-attainment area for both sulfur dioxide and total suspended particulates (TSP). A 2-to-1 offset in sulfur dioxide and a 8-to-1 offset in TSP will be obtained by reducing the emissions of these pollutants from the existing Cardinal Unit 1 Plant. Therefore, the ambient air quality for these pollutants should be beneficially, rather than adversely, affected. Modeling of the minor increases in nitrogen oxides shows that there will be no violations of the ambient air quality standards. The increase in carbon dioxide emissions is less than that of nitrogen oxides and is below the de minimus value. In addition to the above, the offsets in TSP emissions should result in a net reduction in trace metal emissions.

2. Surface Water Quality Impacts

Effects on the surface water quality during construction will be minimal. No construction will be required for barge unloading facilities. Minor maintenance dredging of the existing intake and outfall structures for cooling water may increase the turbidity of the river temporarily.

There will be three effluent streams associated with PFBC operations: sanitary wastes to be treated in the Cardinal Plant's sewage treatment facility, once-through cooling water, and an increase in effluent volume from the Cardinal fly ash pond. The Cardinal sewage treatment is an National Pollutant Discharge Elimination System permitted facility and has adequate capacity. Therefore, no noticeable impacts from this source are expected. The cooling water discharge will have negligible thermal effects since: (1) the magnitude of the temperature increase (8 degrees Fahrenheit) is not excessive, (2) only a portion of the Ohio River cross-section would be affected, and (3) the downstream persistence of the thermal plume would be mitigated through ambient cooling. Finally, a number of small streams associated with PFBC operations will be collected in a sump and discharged to the Cardinal fly ash pond. These streams are runoff from the coal and sorbent storage area and low volume wastewaters from the plant sumps and drains. Since the characteristics of these streams are expected to be similar to the Cardinal Plant wastewaters and since the increase in volume of the total wastewater to the fly ash pond is minimal (less than 4 percent), the impacts are expected to be negligible. Runoff from the ash disposal area will also be directed to the fly ash pond. Since this stream will represent only a slight fraction of the influent to the pond, no measurable impacts are expected to occur.

3. Groundwater Impacts

Impacts to groundwater are limited to withdrawals and infiltration. Neither is expected to have a significant effect. The maximum water withdrawal rate from a single existing well on-site is expected to be 65,000 gallons per day. This will not have any effect on down-gradient wells. With regard to the potential for infiltration at either the coal and sorbent storage area or the ash disposal area, no significant impacts are expected due to mitigative techniques. In the coal and sorbent storage area, a protective base and side liner consisting of compacted clay will minimize seepage of leachate and a runoff collection system will be installed. There are two alternatives for the disposition of PFBC ash: placement on top of the existing Cardinal fly ash pond, pursuant to closure of the pond; or disposal in a separate disposal facility. In either case, the appropriate protection of groundwater will be provided in the form of clay and/or synthetic liners, as required by the state regulatory authority. In addition, groundwater monitoring will be conducted to ensure that any changes in groundwater quality will be detected.

4. Waste Disposal

Wastes generated during operation will include PFBC bed ash and fly ash, small quantities of hazardous wastes, and waste oil. The bed and fly ash will be collected, stored, handled, and disposed in an environmentally sound manner. As stated above, this material will be disposed in the Cardinal fly ash pond or in a separate disposal facility. Samples of representative bed ash and fly ash obtained from test runs at a smaller scale facility (the Component Test Facility in Malmo, Sweden) have been characterized. Leachate tests on these samples have shown that this material should be classified as non-hazardous under Resource Conservation and Recovery Act (RCRA) standards and that, from the perspective of metals listed in the primary drinking water standards, the leachate from PFBC ash is of better overall quality than that from Cardinal Plant fly ash. In addition, the PFBC ash will be integrated into the existing AEP ash marketing program, which is aimed at developing commercial uses for coal-derived ash products. Therefore, the amount of ash to be disposed will be minimized. With regard to hazardous wastes, small quantities of spent degreasing and laboratory solvents will be generated. These wastes will be either recycled or disposed off-site every 90 days, in accordance with RCRA requirements. Waste oil will be sold to a reclaimer.

5. Ecological Impacts

Based on information from the U. S. Fish and Wildlife Service, the plant site is not within the range of any federally-listed endangered species. A detailed biological study has been conducted. This section will only summarize major conclusions of that study.

Construction or operation effects to terrestrial ecology will be minor or negligible, mainly due to the fact that the site is currently industrialized. Construction activities will result in vegetation removal, generation of dust and fumes, and increased vehicular traffic. Several wildlife species will be affected - including rabbit, opossum, squirrel, and a variety of small rodents. These effects will be negligible. Operation effects on terrestrial ecology will be mainly due to air quality impacts. For sulfur dioxide and particulates, there will be a net reduction in emissions. Modeling of emissions of nitrogen dioxide indicates that the maximum ambient concentrations should be well below those levels at which damage to sensitive vegetation may occur.

Construction activities should have a negligible effect on the aquatic ecology. Modification of the site in the past has altered the aquatic habitats such that there are no recorded sensitive habitats or extended spawning areas. In addition, the construction activities will be of limited duration and mitigating actions (such as the use of silt fences and spill containment and control measures) will minimize adverse impacts. Operational effects on the aquatic ecology may result from cooling water intake, discharge of cooling water, discharge of plant wastewaters, spills, and barge traffic. The Ohio EPA has reviewed an intake impact analysis and has determined that the intake structure represents Best Available Technology for minimizing environmental impact. As discussed in Section 2 herein, the impacts of thermal discharge and wastewater effluents on water quality will be negligible; likewise, the effects on aquatic ecology are expected to be negligible. The effects of spillage of coal and/or sorbent material, compared with the existing level of industrial activity, are expected to be insignificant. Spills of oil and chemical products will be mitigated through a Spill Prevention and Countermeasure Plan. The effects of increased barge traffic, compared with current levels, will be negligible.

Although there are no federally listed endangered species in the aquatic ecology, five fish species currently listed as being endangered by the Ohio Division of Wildlife have been collected near the site in the past. Two of these species are rare or absent based on recent studies. The other three species have had adequate reproduction and survival near the much larger Cardinal Plant. This, combined with the relatively low water intake and thermal discharge of the proposed facility, indicates that there will be no significant impact on these species.

6. Floodplains or Wetlands

The proposed plant site is at an elevation four feet higher than the flood of record. There are no wetland areas involved.

7. Noise

A detailed noise impact analysis has shown that the daytime and nighttime average sound levels will not change significantly. Thus, no impact is expected.

8. Land Use and Socioeconomic Impacts

The land use classification of the proposed site will not change and there is no need for acquisition of additional land. During construction, the bulk of the workforce is expected to commute from outside the primary impact area. There is expected to be an overall beneficial socioeconomic impact from construction, with about $15 million directly infused into the local economy. Adverse effects on housing availability, water and sewers, transportation, etc, will be insignificant due to the short construction period, past outmigration, and the small number of workers relocating.

During operation, the predominant socioeconomic effects will be on the local and regional labor force. Employment could increase by up to 80 full-time personnel. Tax revenues should increase with beneficial stimulus to local public services and school systems. Secondary employment will also be increased in the mining sector. These beneficial effects will help to offset the recent and continuing decline in social and economic conditions for this coal-producing region of Ohio.

9. Conflicts with Historic Areas

Based on contact with the Ohio Historical Society, there will be no effect on any potentially sensitive sites in the project area.

10. Permitting Requirements

The permits required for the project include the following:

- Ohio EPA Permit to Install for Air Pollution Control Facilities

- Ohio EPA Permit to Operate an Air Contaminant Source
- Ohio EPA Plan Approval and Permit to Install a Water Pollution Control Facility
- Ohio EPA NPDES Permit
- Ohio EPA Plan Approval and Permit to Install a Solid Waste Landfill if required
- Corps of Engineers' Section 10 Permit (if required for maintenance dredging)

As a result of close coordination with the regulatory authorities, no difficulties are expected in obtaining these permits.

Conclusion

The information available is adequate and sufficient to show that the Tidd PFBC Demonstration Plant Project clearly does not constitute a major federal action significantly affecting the quality of the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

Reference

1. "Tidd PFBC Demonstration Plant: A Report on Environmental Information Needed by the U. S. Department of Energy for an Environmental Assessment," prepared by American Electric Power Service Corporation, December 12, 1986.

J. Allen Wampler

J. Allen Wampler
Assistant Secretary
Office of Fossil Energy

Attachment

cc w/o Attachment:
J. Siegel
C. L. Miller
A. W. Hemenway
A. A. Pitrolo
T. F. Bechtel
P. R. Wieber
W. J. Haggerty
L. M. Joseph
R. L. Scott
W. R. Miller
D. C. Cicero
C. F. Marceron
R. Kesling
L. C. Roberson
L. F. Hemenway
R. A. Hargis

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 10: In August 1986 the Department selected nine projects for negotiation pursuant to the first solicitation. Agreements have been reached for only three of these.

a. When can the committee expect that negotiations will be completed on all nine of these projects?

b. What would be a reasonable length of time at the end of which negotiations could be terminated for lack of progress, and the sponsor directed to resubmit its proposal pursuant to subsequent solicitations?

Answer a: Negotiations have been completed with four of the nine private sector sponsors and the Department had hoped to complete all negotiations by June 30, 1987. However, a firm date of September 30, 1987, has now been set for the completion of the negotiations on the remaining five projects.

b: To ensure that the remaining negotiations are concluded as rapidly as possible, the Department has established interim milestones by which to measure progress. If a proposer is unable to achieve those milestones established for his negotiations, those negotiations could be discontinued before September 30, 1987, unless it can be demonstrated that there is a reasonable likelihood that the final deadline could be met. If the Department cannot conclude negotiations with any of the remaining five project sponsors by September 30, 1987, it would reevaluate the remaining 12 alternate projects and select replacement projects.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 11: Does the President's March 18 pronouncement --

a. Preclude conducting Phase II of the DOE Clean Coal Technology program?

b. Alter the direction or scope of the DOE Clean Coal Technology program to focus it on fulfulling the criteria set forth in the Special Envoy's Report on Acid Rain?

Answer a: On March 18, 1987, the President announced that he would seek the full amount of the U.S. Government's share of funding recommended by the Joint Envoys' on Acid Rain, Drew Lewis of the United States and William Davis of Canada, for the demonstration of innovative clean coal technologies. This decision meant that the Administration intended to request appropriations of $2.5 billion for the funding of a demonstration program involving such technologies over a 5-year period, provided that technically and economically appropriate projects are proposed that meet the program's cost-sharing requirements. The decision and the subsequent complimentary budget request amendment, if supported by the necessary congressional approval, would enhance rather than preclude Phase II of the DOE Clean Coal Technology Program.

b: The decision would alter the direction/scope of the DOE Clean Coal Technology Program to the extent that it more narrowly focuses its activities upon the fulfillment of the Special Envoys' recommendations as fully as practicable, and with due consideration of the guidance provided to the Secretary by the Innovative Control Technology Advisory Panel (ICTAP).

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 12: The President announced that he was establishing an Innovative Control Technology Advisory Panel.

a. What is the anticipated membership of the Panel?

b. What are the anticipated functions of the Panel?

c. Will the Panel have a role in, or be responsible for, designing the Federal program?

d. Will the Panel have a role in, or be responsible for, evaluating specific proposals?

Answer a: It is anticipated that the Panel will be comprised of:

Some of the major features of the Innovative Control Technology Advisory Panel are described in the attached DOE News Media Contact dated June 9, 1987. In addition to a brief description of the membership of this panel, the names of the members identified as of the date of the news release are also given.

b: The anticipated functions include:

- Advise and recommend to DOE activities related to development of innovative emission-control technologies.

- Review programs to determine if they are effectively providing potential added control options.

- Review, evaluate, and advise on proposed project selection criteria for cost shared projects.

- Develop information for us in future solicitations to fill in gaps in technology development programs.

c: The Panel's role in the Federal program will consist of its providing advice and recommendations to the Secretary of Energy on evaluation criteria, scope of projects, and other factors related to the program.

d: It is not anticipated that the Panel will have a role in or be responsible for evaluating any of the specific proposals. The specific proposals will be processed and evaluated in accordance with the financial assistance regulation that govern the Program Opportunity Notice Competitive process.

U.S. DEPARTMENT OF ENERGY
OFFICE OF THE PRESS SECRETARY
WASHINGTON, DC 20585

COAL

DOENEWS:

NEWS MEDIA CONTACT
Will Callicott, 202/586-5806

FOR IMMEDIATE RELEASE
June 9, 1987

MEMBERS NAMED TO CLEAN COAL ADVISORY PANEL

Energy Secretary John S. Herrington has established an Innovative Control Technology Advisory Panel to advise the Department on an expanded demonstration program for clean coal technology.

President Reagan directed the establishment of the panel, which was recommended by the U.S. and Canadian Special Envoys on Acid Rain.

Members of the panel include senior representatives of federal agencies, government representatives from a cross-section of affected states, producers and users of coal, environmental groups, unions and the research community. Included among the members will be two senior representatives of the Government of Canada. Herrington has designated Under Secretary of Energy Joseph F. Salgado to serve as panel chairman.

The panel's recommendations on the scope and funding of future clean coal demonstration projects are to be patterned, as fully as practicable, after guidelines recommended last year in the report of the Special Envoys.

"The President's clean coal initiative is an historic, important and ambitious undertaking," Herrington said. "This panel will play a crucial role in helping meet the President's objectives by advising me on selection criteria for projects, as well as development of our innovative controls program. We have made every effort to ensure that the panel will include a representative cross section of the groups and individuals who have an interest in this area. This advisory panel is a welcome addition to the clean coal program, and I look forward to their counsel and help."

(MORE)

R-87-073

The innovative technologies program will build on DOE's existing Clean Coal Technology Program. Under that program, DOE is providing nearly $400 million in federal financing for nine joint government-industry demonstration projects. Negotiations have been completed for four projects, and an additional five are expected to be underway by early summer.

In March, President Reagan pledged to seek an additional $2.5 billion over the next five years for new clean coal demonstration programs. As part of that expanded effort, DOE will seek Congressional approval for an $850 million solicitation for additional projects in late 1987.

The panel will include:

Joseph F. Salgado, Chairman
Under Secretary
Department of Energy

Richard Balzhiser
President
Electric Power Research Institute

Fred O. Braswell, III
Assistant Director and
  Division Chief
Alabama Department of Economic and
  Community Affairs

Robert K. Dawson
Associate Director for
  Natural Resources, Energy and Science
Office of Management and Budget

J. William Futrell
President
Environmental Law Institute

William J. Lhota
Senior Vice President
Columbus and Southern Ohio
  Electric Company

Peter MacDonald
Chairman
Navajo Tribal Council

Nancy Maloley
Commissioner
Indiana Environmental
  Protection Agency

Joan T. Bok
Chairman
New England Electric System

Bobby Brown
President
Consolidation Coal

William Esler
President and CEO
Southwestern Power Service Co.

William Kelce
Executive Director
Alabama Coal Association

Paul Locigno
Director of Government Affairs
International Brotherhood of
  Teamsters

J. Curtis Mack, II
Assistant Secretary for
  Oceans and Atmosphere
Department of Commerce

William McCollam, Jr.
President
Edison Electric Institute

(MORE)

John McCormick
Greenpeace, U.S.A.

John Negroponte
Assistant Secretary for
Oceans and International
and Scientific Affairs
Department of State

J. Craig Potter
Assistant Administrator
Environmental Protection Agency

John H. Skinner
Director, Office of
Environmental Engineering
and Technology
Environmental Protection Agency

Richard Trumka
President
United Mine Workers

Mary L. Walker
Assistant Secretary for
Environment, Safety and Health
Department of Energy

Robert L. Wise
Chief Executive Officer
Pennsylvania Electric

William B. Marx
President and Founder
Council of Industrial
Boiler Owners

Mary Eileen O'Keefe
President and CEO
Lakeshore International, Ltd.

Robert H. Quenon
President and CEO
Peabody Holding Company

James E. Sparkman
Chief Executive Officer
Kaiser Aluminum

Norman P. Wagner
President and CEO
Southern Indiana Gas & Electric

J. Allen Wampler
Assistant Secretary for
Fossil Energy
Department of Energy

Randolph Wood
Director, Department of
Environmental Quality
State of Wyoming

Additional members will be proposed by the governors of Illinois, Michigan, New Hampshire, Pennsylvania and Wyoming, the Department of the Interior, and by the Government of Canada.

-DOE-

R-87-073

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 13: S. 879 addresses Federal and State regulatory issues affecting the deployment of clean coal technologies.

a. For each of the regulatory issues addressed, would you agree that it is an impediment to the deployment of clean coal technologies? If so, do you agree with the proposed legislative solution? If not, what legislative solution would you propose as an alternative?

b. What other regulatory issues do you feel should be considered for inclusion in S. 879 in order to encourage deployment of clean coal technologies?

Answer a: DOE is in the process of examining the regulatory issues addressed in S. 879. However, it is too early for us to give you a comprehensive agency position on these issues or to suggest other possible regulatory actions. As you know, the Presidential Task Force on Regulatory Relief, which is chaired by the Vice President, is also looking at many of the same issues--and possible solutions--within the context of other possible disincentives beyond economic obstacles.

b: In principal, utility regulation should allow the development of a broad slate of technologies based on an objective evaluation of their technical and economic characteristics.

QUESTIONS SUBMITTED BY SENATOR McCLURE

CLEAN COAL TECHNOLOGY PROGRAM

Question 14: S. 879 addresses coordination with States' governmental representatives.

a. For each of the intergovernmental issues addressed, would you agree that it is an issue affecting the deployment of clean coal technologies? If so, do you agree with the proposed legislative solution? If not, what legislative solution would you propose as an alternative?

b. What other intergovernmental issues do you feel should be considered for inclusion in S. 879 in order to encourage deployment of clean coal technologies?

c. What consultation with State and local governments prior to approval of financial assistance would be appropriate? Should this extend to pre-approval by State and local governments?

Answer a: Each of the intergovernmental issues addressed in S. 879 could affect the rate at which clean coal technologies are demonstrated and subsequently deployed. While in general the Department agrees that regulatory and related discentives to the demonstration and use of these technologies should be eliminated, it is too soon for us to give a comprehensive view of the agency's position on potential remedial actions.

b: Because we now have this area under study, we cannot offer you a definitive answer to this question.

c: The Department's position is that it would be appropriate to and consistent with the planning activities and implementation of any subsequent phases of the Clean Coal Technology Program to have consultations with State and local governments, regarding their positions on providing regulatory (and related) incentives, at their levels, to encourage the deployment of certain technologies. Some of these meetings have already taken place and the Department has scheduled a series of four public meetings to be located in cities in the West, Midwest, and Eastern parts of the United States (Albuquerque, New Mexico, St. Louis, Missouri, Pittsburgh, Pennsylvania and Washington, D.C.). These meetings will provide the opportunity to receive significant information relative to attitudes, desires, objectives, etc., of the public in any subsequent solicitation. It should be noted also that the Office of Fossil Energy is actively working on Memorandum of Understanding with various states. However, we do not feel it would be appropriate or even possible based upon Federal Financial Assistance Regulations to give state and local governments pre-approval rights.

National Association of Regulatory Utility Commissioners
Incorporated

PETER A. BRADFORD, *President*
Maine Public Utilities Commission
242 State Street, State House Station 18
Augusta, Maine 04333

BRUCE HAGEN, *First Vice President*
North Dakota Public Service Commission
State Capitol
Bismarck, North Dakota 58505

HENRY G. YONCE, *Second Vice President*
South Carolina Public Service Commission
111 Doctors Circle, Post Office Box 11649
Columbia, South Carolina 29211

1102 Interstate Commerce Commission Building
Constitution Avenue and Twelfth Street, N.W.
Post Office Box 684, Washington, D.C. 20044-0684

Telephone: 202-898-2200

PAUL RODGERS
Administrative Director
General Counsel

GAILE ARGIRO
Treasurer

June 25, 1987

The Honorable J. Bennett Johnston, Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510-6150

Attention: Cheryl Moss

Dear Senator Johnston:

This letter is in response to your letter dated June 9, 1987, which enclosed follow-up questions from Senator Ford concerning my testimony on clean coal before your Committee on May 18. The questions and answers follow:

> 1) At the hearing on S. 879 on May 18, you indicated a desire to provide input during the clean coal technology project selection process. Specifically, what type of input would a public utility commission like to provide? How would you suggest that a public utility commission provide input into the selection process while assuring that project selection is achieved in a timely fashion.

Concerning the first part of this question, let me first distinguish between what role the NARUC feels it should play and how an individual commission should be involved in the clean coal technology project selection process.

NARUC feels very strongly that it should be represented on the Clean Coal Advisory Panel recently established by Energy Secretary Herrington. In the June 9 DOE Press Release announcing appointments to this panel, it is stated that:

> "Members of the panel include senior representatives of federal agencies, government representatives from a cross-section of affected states, producers and users of coal, environmental groups, unions and the research community."

We find it very disappointing, and somewhat alarming, that, although a broad cross-section of parties is indeed represented, not one member of either a Federal or State ratemaking agency is listed as having been appointed to the Panel.

The NARUC represents a body of expertise which is solely concerned with the economics of utility investment and operation. Our primary goal, as stated in our testimony, is to balance the needs of ratepayers with those of a utility's shareholders, allowing the utility an opportunity to earn a fair rate of return in a market in which it operates as a monopoly while trying to ensure that its captive customers are provided with reasonably-priced service.

Clean coal technology projects, unless funded 100% by tax dollars, will involve significant investment on the part of the utilities involved in those projects. A utility's ratepayers will in turn bear their burden of those costs. In short, in addition to the political, environmental and technical aspects of clean coal technology there exists a significant economic aspect as well. As utility commissions are primarily concerned with the economic aspects of regulation -- i.e. ratemaking -- it seems fitting to include on the Panel a representative who can bring this type of expertise into the project selection process. All the relevant impacts of clean coal technologies need to be addressed and we feel it is an oversight of some proportion that an important aspect of the economic consideration involved in such projects has apparently been overlooked.

Specifically, there are four primary areas in which a NARUC representative could provide input into the project selection process:

1) Providing an understanding of the regulatory process and helping to ensure that a clean coal technology project is properly designed from a ratemaking point of view;

2) Assisting in the development of criteria for project selection, such as cost/benefit analyses and analysis of the purpose and applicability of a project vis-a-vis local and regional variabilities and the nature of the particular service to be supplied;

3) Analysis of the design of the financial package to be used, particularly concerning the use of utility funds; and

4) Assistance in the design of clean coal technology projects to ensure that, to the greatest degree possible, funds will be allocated in a prudent and efficient manner.

Apart from the FERC (which also is surprisingly absent from the Secretary's Panel), the NARUC is in many ways the only party which can bring this type of expertise to bear, and, importantly, we wish to stress that the NARUC would assist as a cooperative agent in this process. Although our focus is economic regulation, we are well aware of, and in agreement with, the social -- i.e. environmental -- goals to which this debate is addressed. To that end, we would provide objective counsel to our colleagues on such a panel.

The question of how a particular State commission could provide input vis-a-vis a particular clean coal project is more complicated. First, let me make it very clear that a State commission is not at all likely to impede the development of worthwhile and well-managed pollution control projects. It is not clear, however, whether a commission should be part of the actual planning of a specific project. Quite simply, if regulators participate directly in the planning stages of a particular project they in effect become part of management and lose their ability to regulate objectively. Our view, therefore, is that the NARUC should participate at the DOE level of the project selection process, but individual commissions should remain in an oversight capacity relative to the implementation of a specific project, ensuring that ratepayer funds are used efficiently.

Finally, we do not think that NARUC participation on the Secretary's Panel would interfere in the timely selection of clean coal technology project selection process.

> 2) What does NARUC think about the idea of having federal assistance under a program like that described in S. 879, notwithstanding section 4(a)(4), contingent upon an agreement between the state regulatory commission and the utility for provision of certain regulatory benefits -- in other words, having the utility and the public utility commission "sign on the dotted line" before coming to the Federal government for assistance?

This does not appear to be a workable concept. Clearly a State commission cannot enter into an agreement which would in any way violate State law. If, for example, a State statutorily denies CWIP (which many do), such a regulatory benefit would be legally untenable within that State. Additionally, how would such an agreement be enforced? It is also of some concern that this type of approach might be viewed as the Federal government using grant funds to "coerce" changes in State law and policy. This is an approach which we do not feel is appropriate or necessary. It seems fairly obvious that in the States which would appear to be most affected by clean coal technology development -- i.e. high sulfur coal States -- there already exists a vested interest in seeing these technologies become commercially viable.

I would note, however, that State regulators might agree to the Federal grants program being contingent upon some type of pre-approval process, where the jurisdictional State agencies (Environmental, Natural Resources, Public Service Commission, etc.) mutually agree (in whole or part) to approving in advance a utility's decision to invest in a DOE-designated clean coal technology. This would not, however, be considered a presumption of prudence regarding the construction and operational aspects of the particular project, but would represent a clear indication from a State that a carefully managed investment in clean coal technology is worth the risk, relative to the potential benefits. In other words, we see a potentially workable distinction between planning and approving. The NARUC cannot at this time commit to such an approach, but indications from several of our members are that, if drafted carefully, this might be an equitable concept. We reserve final judgement pending review of any such language which might be proposed.

In closing, let me note that we are cognizant of the dilemma you face and sincerely appreciate the opportunity to cooperate with you and your distinguished colleagues in this extremely important debate. We strongly support your efforts to create reasonable and workable clean coal deployment legislation and will, without hesitation, offer any further assistance which you may require.

Very truly yours,

Edwyna G. Ander

Edwyna G. Anderson J.M.F.
Michigan Public Service
Commission

Chair, NARUC Committee
on Electricity

WALKER F. NOLAN, Vice President, Legislative Affairs

EDISON ELECTRIC INSTITUTE The association of electric companies

1111 19th Street, N.W.
Washington, D.C. 20036-3691
Tel: (202) 828-7400

July 7, 1987

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Mr. Chairman:

Enclosed are responses to the questions submitted to EEI by Senator Wendell Ford for the record of your Committee's May 18 hearing on S.879, the "Clean Coal Technology Deployment Act." EEI and our witness, Mr. John O'Leary, Chairman of General Public Utilities Corporation, appreciated the opportunity to participate in your hearings on this important initiative.

Please do not hesitate to call on us if we can provide further information.

Sincerely,

Walker F. Nolan

Walker F. Nolan

Enclosures

FOLLOW-UP QUESTIONS FOR EEI

HEARING ON S.879 -- MAY 18, 1987

From Senator Wendell Ford

1. Critics have argued that additional research on clean coal technologies is not necessary and that clean coal technologies are sufficiently mature for commercialization.

- Please comment on the maturity of various clean coal technologies.

- When will they be available for deployment?

- Please describe those factors which present the most significant technological risks to widespread deployment of clean coal technologies and would require additional research before commercialization would occur. Please provide information on at least the following technologies: advanced physical coal cleaning; furnace injection; duct injection; limestone injection multistage burner; integrated gasification combined-cycle; advanced fuel gas desulfurization; gas reburning; atmospheric fluidized bed combustion; and pressurized fluidized bed combustion.

RESPONSE

The exact dates for commercial availability of various technologies are speculative. Estimates, however, are included both in testimony by the Electric Power Research Institute (EPRI) before the Energy Research and Development Subcommittee on April 2, 1987 and in the Department of Energy's recent study entitled America's Clean Coal Commitment. From these and other sources, we know that different technologies are at different levels of maturity and, consequently, will require different timeframes for development. Some technologies may be demonstrated in 3-5 years. Others, however, may not be demonstrated for 10 years or even longer.

Appendix I to EPRI's April 2nd testimony provides their assessment of the status and demonstration requirements for each of eleven clean coal technologies. It includes, also, a table that organizes the eleven technologies into six categories and summarizes their major risk factors that must be resolved during the demonstration process. This information is attached.

2. How many demonstration projects for each type of technology are necessary to convince potential users -- utilities and industries -- that the technologies are both cost-effective and reliable? How large should these demonstration projects be?

Again, the number and size of the demonstration projects will vary according to the technology, as is reflected in the attached EPRI summaries.

Even after the technical capabilities of a technology have been demonstrated, several pioneer, commercial-sized facilities may have to be constructed and operated before that technology will be considered an acceptable option with acceptable commercial risks. As additional units are built and brought into service, experience is broadened, improvements are incorporated into the design and commercial acceptance is gained as costs come down and reliability and availability improve.

Table 2, developed by EPRI, illustrates the characteristic learning curve associated with the development and commercial deployment of new technology.

3. Do the regulatory incentives in the Byrd bill, either together or individually, provide incentives for increased deployment of clean coal technologies?

RESPONSE

The regulatory provisions in S.879 would help to overcome the obstacles to new technology development and use that are unique to the regulated utility industry.

As stated in my testimony, there is a strong inclination on the part of utilities and the commissions which regulate them for the industry to confine themselves to proven technologies when significant levels of investment are required. In this risk averse climate, a utility could face a substantial or even total disallowance of its costs if an untried technology does not meet expectations. Also, the potential that currently exists for retrospective prudency review means that utilities can be second guessed by their utility commissions long after substantial commitments and expenditures have been made. Even if the technology proves to be successful, the amount and timing of any return on what is a risky and substantial investment will be uncertain, depending upon whether, when, and to what extent public utility commissions treat these expenditures in establishing base revenues.

Federal regulatory changes that would create more certainty that reasonable investment costs could be recovered would facilitate the commercialization of these technologies.

4. What do you believe to be the appropriate role of the states in furthering clean coal technologies? Is there anything that the federal government can do to encourage or influence state support of these technologies?

Since it is the states that have much of the regulatory authority that will affect the future success of the clean coal program, the cooperation and participation of the states is critical. The Department of Energy and the Environmental Protection Agency could serve as valuable sources of information and encouragement to the states to facilitate the demonstration and deployment of clean coal technologies. Federal cost-sharing could be available for state supported projects. In addition, Federal regulatory changes could serve as a model for state regulatory agencies that share the federal government's interest in in accelerating technology development.

TABLE 1
CLEAN COAL TECHNOLOGY APPLICATIONS AND RISKS

TECHNOLOGY	CAPITAL COST ($/KW)*	NET COST EFFECTIVENESS $/TON SO_2 OR NO_x REMOVED	APPLICABILITY		RISK FACTORS REQUIRING RESOLUTION
			RETROFIT	REPOWER/ NEW	
Coal Cleaning and Upgrading					
A. Advanced Physical Coal Cleaning	60-100	400- 600	X	X	• Degree of sulfur removal • Btu recovery • Increase in coal moisture • Economic agglomeration technology
B. Low Rank Coal Upgrading	60-120	400-1000	X	X	• Capital cost of equipment • Btu recovery • Product quality
2. Wet FGD					
A. Advanced Conventional FGD	200-300	400- 600	X	X	• Capital costs of redundancy and materials • O&M cost savings through elimination of reheat
B. Advanced Regenerable FGD	300-400	500- 700	X	X	• Capital costs of materials and redundancy • O&M costs associated with membrane plugging, sorbent use
3. Dry SO_2 Control					
A. Furnace Sorbent Injection	50- 75	700- 900	X		• Boiler impacts • ESP Upgrade costs • Waste management
B. Duct Sorbent Injection	50-100	500-1000	X		• Duct deposition (calcium systems) • Baghouse performance (hybrid system) • Soluble wastes, NO_2 plume, sorbent cost and availability (sodium system) • Particulate control/humidification • Waste management

TECHNOLOGY	CAPITAL COST,* ($/KW)	NET COST EFFECTIVENESS $/TON SO_2 OR NO_x REMOVED	APPLICABILITY RETROFIT	APPLICABILITY REPOWER/ NEW	RISK FACTORS REQUIRING RESOLUTION
4. NO_x Control					
A. Low NO_x Combustion and Reburning	5- 35	100- 500	X	X	• Effects on carbon burnout, flame efficiency and stability, slagging and corrosion
B. Postcombustion	75-100	1000-4000	X	X	• O&M costs of catalyst replacement • Availability loss due to air heater cleaning
5. Fluidized Bed Combustion					
A. Atmospheric	600-1600[a]	200- 500[b]		X	• Capital and O&M costs of heat transfer surface and solids handling systems
B. Pressurized	800-1500[a]	200- 450[b]		X	• Capital costs as per AFBC • O&M costs of sorbent utilization and gas turbine maintenance
6. Integrated Gasification Combined Cycle	1300-1900[a]	200- 400[b]		X	• Capital costs of design conservatism • O&M costs of heat transfer fouling, refractory & sulfur recovery • Availability loss during startup

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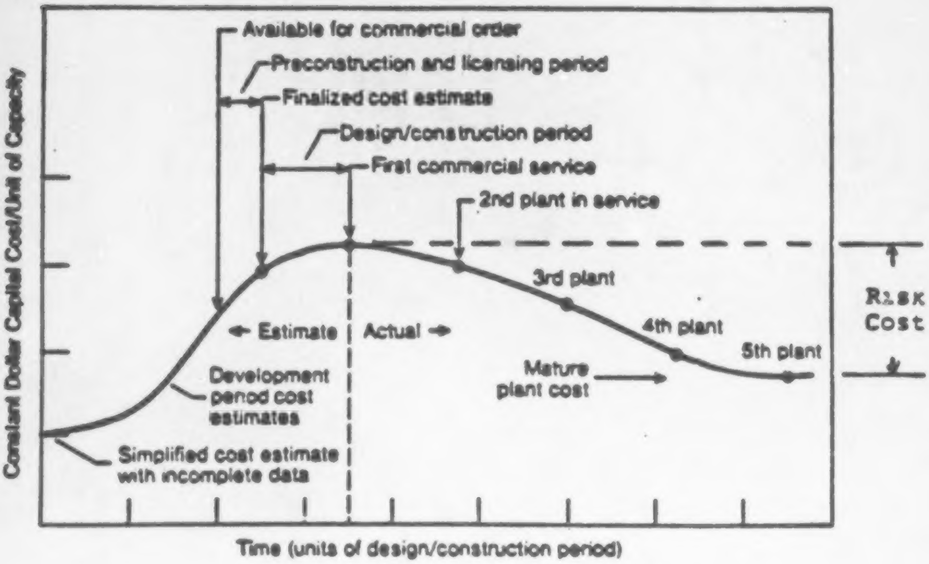
[*] For an approximately 250 MW retrofit/repower on medium to high sulfur coal (2.5-4% sulfur in 1[illegible] dollars.

[a] Total installation cost range reflects repower and new applications.

[b] Net SO_2/NO_x control cost effectiveness based on fraction of total capital and operating cost assigned to emission control.

~~Figure 7~~

Table V


Available for commercial order
Preconstruction and licensing period
Finalized cost estimate
Design/construction period
First commercial service
2nd plant in service
3rd plant
4th plant
5th plant
Mature plant cost
← Estimate
Actual →
Development period cost estimates
Simplified cost estimate with incomplete data
Risk Cost
Constant Dollar Capital Cost/Unit of Capacity
Time (units of design/construction period)

Cost Learning Curve

Appendix 1

CLEAN COAL TECHNOLOGY OPTIONS

1. COAL CLEANING AND UPGRADING

a. Advanced Physical Coal Cleaning

Description: Advanced physical coal cleaning involves four basic operations: (1) fine crushing of all coal cleaned to achieve high pyritic sulfur and ash liberation; (2) use of advanced physical cleaning processes such as microbubble flotation, selective flocculation, true heavy liquid separation, or some combination; (3) use of advanced fine coal physical dewatering technology; and, (4) clean coal agglomeration to produce a handleable product. Advanced physical coal cleaning technology could be combined with conventional cleaning technology in ways that result in cleaning plants that produce multiple fuels of different quality, such as low-sulfur coal for conventional firing and a high-sulfur coal for fluidized bed combustion firing. This technology has the potential to double coal pyritic sulfur removal over currently available cleaning methods from approximately 40% to 80% removal. The estimated ultimate cost of this technology is \$400-600/ton of SO_2 removed including credits associated with utility firing of improved quality coal.

Status:. An EPRI survey identified 25 developmental, physical fine coal cleaning processes. The most promising processes are being evaluated at 1 ton/hour scale under a joint DOE-EPRI project at the EPRI Coal Cleaning Test Facility. This testing program, which is scheduled to run through 1989, will provide the basis for demonstration plant design. EPRI, Ohio Edison, and the Ohio Coal Development Office are evaluating multi-product coal cleaning at a scale of 20 tons/hour. EPRI, DOE, and the Alberta Research Council are developing a desulfurization process based on oil agglomeration. The Central Electricity Generating Board (UK) is developing a dry magnetic coal cleaning process. Several private U.S. companies are developing processes at bench-scale.

Demonstration Requirements: Major developmental issues are process performance, a viable clean coal agglomeration process, and economics. To be considered commercial technology for major U.S. coal types, 5-7 demonstration plants would be required with clean coal capacities on the order of 150 tons/hour. These demonstration plants would involve different advanced physical coal cleaning, dewatering, and agglomeration technologies and different combinations of these technologies with conventional cleaning technology. The estimated cost of a typical demonstration project (3-5 year duration) is $40-60 million.

b. Low-Rank Coal Upgrading

Description: Low-rank coal upgrading processes produce a high-Btu, low-sulfur, low-moisture, low-ash fuel by thermally removing moisture and, in some processes, sulfur and/or ash from subbituminous coal or lignite. To produce a product with handleability and storability comparable to high quality bituminous coal, coal particle surfaces are altered during upgrading, or subsequent to it, to reduce moisture re-absorption. These processes can potentially produce compliance coal (less than 1.2 lbs SO_2/MBtu) from many western coals and lignite. Estimated upgraded coal cost is $30-40/ton, f.o.b. plant.

Status: Western Energy, Amax Coal, K-Fuel, ARCO, Mobil, Bechtel, the University of North Dakota Energy Research Center, and others are developing upgrading processes. Western Energy is operating a 200 lb/hour pilot plant and has proposed to build a demonstration plant under the Federal Clean Coal Program. K-Fuel is operating a 500 lb/hour pilot plant and is planning a 100 ton/hour demonstration plant in the Powder River Basin. Several major western coal producers have announced plans for coal or lignite upgrading projects.

Demonstration Requirements: Major development issues are ultimate product quality and economics. To determine which of the competing technologies are commercially viable and account for coal and lignite processing differences, 3-5 demonstration plants with upgraded capacities on the order of 150 tons/hour would be required. The estimated cost of a typical low rank coal upgrading demonstration project (3-5 year duration) is $40-50 million.

2. WET FGD

a. Advanced Conventional FGD

Description: Improvements in conventional FGD can be illustrated using three examples. First, process improvements such as the jet bubbling reactor used in the Bechtel CT-121 Process; second, application of spray drying to high sulfur coal; and third, an advanced, conventional limestone FGD system producing gypsum with no reheat and no redundant modules for use at compact sites. Each of these designs can achieve 90 to 95% SO_2 control. The cost and performance advantages are a 20-50% capital cost savings and 20-40% operating cost savings over conventional FGD systems available today. The jet bubbling reactor and advanced limestone/gypsum designs can both make wallboard grade gypsum for sale or disposal. Capital costs for such systems will vary depending on a number of factors such as fuel sulfur content and unit size. Typical retrofit cost for a 200 MW unit burning medium to high sulfur coal (2.5% to 4%) is about $200-$300/kW.

Status: Several advanced conventional FGD processes are being or have been tested at large pilot and commercial scale. The CT-121 process has been piloted on high sulfur coal at 23 MW by EPRI and is operating in Japan on 3% sulfur coal at 250 MW. A 40 MW industrial unit will be tested in 1987 by EPRI and the State of Illinois. Bechtel is attempting to sell a commercial utility unit; EPRI would test the unit's performance which is planned to occur in 1989-1990.

The high sulfur coal spray drying designs adapt the successful concept currently used on 7000 MW of low sulfur coal capacity. Two pilot plants are currently starting operation to test performance on high sulfur coal. TVA, Ontario Hydro, and EPRI are testing a 10 MW spray dryer/ESP combination at Shawnee, and EPRI is testing a 4 MW spray dryer fabric filter at the High Sulfur Test Center near Buffalo. Testing should be complete in 1989. A full-scale 160 MW demonstration of a high sulfur spray dryer/fabric filter has been proposed by TVA for funding under Phase II of the Clean Coal Technology program with testing to be completed in 1991.

Advanced conventional FGD systems using limestone and producing a salable gypsum byproduct with no spare modules, no stack gas reheat and gypsum byproduct sales have not been demonstrated at pilot or full scale in the U.S. EPRI will pilot test these improvements at the High Sulfur Test Center at 4 MW. New York State Electric and Gas has proposed testing this system at 168 MW as part of the Phase II Clean Coal Technology program concluding in 1989-1990.

Demonstration Requirements: Issues requiring resolution include: finding suitable commercial sites for demonstrations of advanced processes such as CT-121 and providing risk cost sharing for the work; establishing the performance and cost associated with high sulfur spray drying; and establishing the reliability and performance of a simplified advanced limestone FGD system producing gypsum. For these example systems, the number of demonstrations desirable to reach commercial acceptance include two jet bubbling reactor systems - one using a presorubber and one without; two high sulfur spray drying demonstrations, one with an ESP and one with a fabric filter; and two advanced limestone systems with different absorber oxidation tank arrangements. Each demonstration should be at least 100 MW in size using at least 3% sulfur content coal. Total costs for these demonstrations is approximately $140 million.

b. Advanced Regenerable FGD

Description: Advanced regenerable FGD systems can use diverse physical and chemical principals, but generally recover sulfur byproducts as concentrated SO_2, sulfuric acid, or elemental sulfur. Three SO_2 or SO_x/NO_x processes illustrate the development status of advanced regenerable FGD processes. One process combines a conventional sodium based scrubber with electrolytic regeneration of the scrubbing solution using a bipolar membrane (e.g., SOXAL). Another process uses dry activated carbon (char) pellets to adsorb SO_2, with NH_3 injection to remove limited amounts of NO_x (e.g., Mitsui). A third process removes SO_2 and NO_x by chemisorption in a surface layer of sodium carbonate deposited on a gamma-alumina substrate (e.g., NOXSO). The sodium scrubbing process can remove over 95% of the SO_2 but no NO_x. The activated carbon process can remove over 95% of the SO_2 and 40%-60% of the NO_x. The chemisorption process can remove about 90% SO_2 and 90% NO_x. The processes are more capital intensive than throw-away FGD (approximately $300-400/kW for regenerable systems versus $200-300/kW for a comparable gypsum system), but are projected to be competitive in levelized cost (approximately $600/ton SO_2 removed). The major advantage is in elimination of waste disposal costs.

Status: The advanced regenerable FGD processes are currently at small pilot scale with the exception of activated carbon process which has a 100 MW prototype operating on low sulfur coal in Japan. The sodium scrubbing process is being tested at small pilot scale (0.4 MW in Canada) and will soon be tested at 0.4 MW at EPRI's High Sulfur Test Center. A full-scale test has been proposed at an Illinois power plant in response to the Phase II Clean Coal Technology program. The chemisorption process has undergone pilot development in Japan, and is operating at the Omuta station of Mitsui Aluminum on a 100 MW base load coal-fired boiler. The process has been tested on a 50 acfm slip stream at TVA's Shawnee station and, more recently, at 1 MWe equivalent at DOE's PETC facilities. Additional tests are planned at this scale through 1987.

Demonstration Requirements: All of these systems require full-scale prototype testing on U.S. coals to verify system performance and costs and establish that they are competitive with conventional FGD. The issues regarding sodium scrubbing are whether the membrane can tolerate small amounts of flyash contamination, and whether optimized system operation will result in competitive economics. The activated carbon process issues include sorbent attrition and controlling dust emissions from the char. The chemisorption process issues include sorbent attrition, materials choice, and reducing gas use for regeneration.

The demonstrations required to ready these processes for the commercial market include: 2 sodium scrubbing process demos - one producing liquid SO_2 and one using off-peak power for regeneration; one activated carbon process demo on high sulfur U.S. coal; and two chemisorption process demonstrations, one aimed at moderate (50%) NO_x removal and one aimed at 90% NO_x removal. Each demonstration should be at least 100 MW in size using at least 3% sulfur content coal. Total costs for these demonstrations would be approximately $180 million.

3. DRY SO_2 CONTROL

a. Furnace Sorbent Injection

Description: Furnace sorbent injection (FSI) refers to the injection of calcium-based sorbents (lime or limestone) into the radiant zone of the furnace where it calcines and then reacts to form $CaSO_4$ in the 2300-1600°F temperature range. The sulfated sorbent is then collected along with the fly ash in the precipitator or baghouse. An alternate process, convective pass injection (CPI), is a similar process in which the sorbent is injected near the economizer at approximately 1000°F.

SO_2 removal for FSI is a function of sorbent choice and quantity injected but is typically 35-45% with limestone and 50-60% with lime at injection rates corresponding to calcium to sulfur ratios of two. The process is characterized by low capital costs (approximately $50/kW), simplicity of design and operation, and costs which are about $200 - $500/ton of SO_2 removed lower than those typical of wet FGD. CPI performance and costs are presently comparable to those for FSI. The lower temperatures at the injection location and the extremely fast reaction rates hold promise of performance improvements using enhancement techniques which are inapplicable at FSI temperatures.

Status: FSI is being demonstrated at full-scale at two U.S. power plants: (1) Ohio Edison's Edgewater Plant by USEPA, USDOE, the State of Ohio, and others; and (2) Richmond Power and Light's Whitewater Valley station by EPRI and USEPA following extensive pilot scale development by EPRI and EPA. Several smaller scale industrial demonstrations in the US and utility demonstrations in Canada and Western Europe have been successfully completed.

CPI is still in the bench and pilot-scale development stage, although limited full-scale tests of an unoptimized system at Saskatchewan Power's Boundary Dam plant suggest that pilot results can be achieved in practice.

Demonstration Requirements: Although FSI is furthest developed of the several dry SO_2 control technologies, full-scale demonstration is needed to resolve potentially adverse impacts on plant operations. These include fouling of convective pass heat transfer surfaces in the furnace, excessive particulate emissions, and solid waste management and disposal problems resulting from increased by-product quantities and the high reactivity of the unreacted sorbent. In addition, methods must be explored to reduce sorbent use and costs through sorbent recycle, downstream humidification, or supplemental duct injection to extend the range of units for which the technology would be economical.

Two or three additional demonstrations beyond those two currently underway should include application to a cyclone unit with high flue gas quench rates and application of sorbent injection in combination with reburning for NO_x control. Two such demonstrations are planned as part of the DOE Phase I Clean Coal Technology program to be conducted in Illinois with support of the state of Illinois, the Gas Research Institute, and the city of Springfield. Additional projects were proposed in the DOE Phase II solicitation including a comprehensive cyclone demonstration in Wisconsin. The demonstrations should be complete by early 1990 at a cost of approximately $30 million.

b. Duct Sorbent Injection

Description: Duct sorbent injection refers to those processes where the sorbent is injected into low temperature flue gas downstream of the air preheater. SO_2 removal can be accomplished with either sodium- or calcium-based sorbents. In the case of calcium-based sorbents, it is necessary to humidify the flue gas to within 40-20°F of the saturation temperature in order to achieve sufficiently high reaction rates for economical SO_2 capture. This can be accomplished either through separate humidification followed by dry sorbent injection or through slurry injection in the case of in-duct spray drying.

As with furnace sorbent injection, these processes are characterized by moderate sulfur capture (40 to 70% SO_2 removal), simplicity of design and operation, low capital cost and attendant savings in levelized removal costs. Several varieties of the basic technology are possible including in-duct spray drying using a slurry, dry duct injection using sodium or calcium sorbents, and a hybrid system which includes retrofit of a fabric filter after the existing ESP. In the latter, a dry calcium sodium sorbent is injected into the clean gas stream following the ESP. All have capital costs of about $50/kW with the exception of the hybrid system which is about $100/kW due to addition of the baghouse. However, the latter is potentially capable of about 70 percent SO_2 removal (versus about 40-50% for the others) resulting in a cost effectiveness of about \$600-650/ton of SO_2 removal making it an attractive alternative to other dry systems.

Status: Table A-1 summarizes the stage of development for each process, the important development projects currently underway in the US, and the important issues to be resolved prior to commercial availability. Each of the processes for which pilot-scale development is successful will require full-scale demonstration to resolve operating issues such as particulate control, waste management and disposal, and the severity of duct deposition, plugging, and corrosion.

Demonstration Requirements: As indicated in Table A-1, the dominant issue for all of the calcium-based processes is humidification and whether it can be achieved without unacceptable duct deposition or precipitator degradation. It is likely that as many as a dozen demonstrations will be required to cover the range of processes, coals, and particulate controls. Several of these demonstrations may be combined with FSI demos currently underway at Edgewater and Richmond. The demonstrations could be completed by 1992-3 at a cost of \$2 to \$4 million each.

4. NO_x CONTROL

a. Combustion Modification

Description: Combustion modification achieves NO_x reductions through the redesign of burners or through rearrangement of the fuel and air flows to the furnace (such as overfire air or reburning) in order to control the mixing of the fuel and air in relationship to the local temperature patterns. Maintenance of fuel rich conditions in the primary flame zone followed by gradual air addition later in the combustion process minimizes NO_x formation. Reburning involves the redirection of 10-20% of the total fuel to the mid-furnace region to create a zone for reduction of NO_x formed in the primary burner zone. Such methods are applicable to oil and gas units as well as coal.

Achievable reductions are typically 40-60% although a combination of methods (low NO_x burners followed by reburning, for example) may achieve 75-80% reduction over uncontrolled emissions in some cases. Capital costs for retrofit low NO_x burners are estimated at \$5 to \$10/kW with no additional operating costs expected. Reburning costs depend on the choice of reburning fuel (gas, oil, or coal) with capital costs ranging from \$20 to \$35/kW and operating costs dominated by fuel cost differentials from the base coal costs.

Status: Combustion modification has been widely applied at full scale on new units to meet NSPS on coal-fired utility boilers and for both new unit and retrofit applications on oil- and gas-fired units. Pilot development of retrofit approaches to coal units has progressed to the point where technologies are ready for demonstration on three major categories of existing boilers (tangentially-fired, wall-fired with circular burners, and cell burners). A full-scale demonstration (350 MW) of the PM (pollution minimization) burner on a tangentially-fired unit is now underway at KPL Gas Service's Lawrence Energy Center Unit #5. Sponsors include EPRI, KPL, Combustion Engineering, and the Kansas Electric Utilities Research Program. Burner installation will occur Spring 1987 and the demonstration period is one year. A wall-fired demonstration is planned for Homer City Unit 1 or Unit 2 (650 MW) in mid-1988. Pilot work is underway at Babcock & Wilcox on reburning for specific application to cyclone units under EPRI/GRI sponsorship.

Demonstration Requirements: Remaining development requirements are primarily related to questions of operability. These include demonstrating that NO_x reductions can be achieved without adverse effects on carbon burnout, furnace efficiency, flame stability, slagging or corrosion. In addition to the planned demonstrations of low NO_x burners, systems combining reburning with these burners on tangentially-fired and wall-fired units are needed. Several candidate demonstration projects have been submitted to USDOE in Phase II of the Clean Coal Technology submissions. Three to five additional demonstrations could be completed by 1992-3 covering all categories of pre-NSPS units, including the promising combined systems. Based on experience to date, these demonstrations would cost from $2 to $4 million each.

b. Post-Combustion NO_x Control

Description: Post-combustion NO_x control refers to flue gas treatment methods for conversion or removal of NO_x species external to the furnace. The most common processes involve the injection of ammonia or ammonia-like compounds (urea, isocyanic acid) into the flue gas with or without a catalyst to promote the reduction of NO_x to nitrogen and water vapor. The most extensively developed process is selective catalytic reduction (SCR) in which ammonia is injected into the flue gas at about 800°F in the presence of a vanadium pentoxide catalyst.

NO_x reductions of 80% or more are possible with SCR alone and, if used in conjunction with a low-NO_x burner achieving 50% initial reduction, a combined efficiency of 90% can be obtained. Costs are high, at $75 to $100/kW, and removal costs are estimated at $4000 to $8000/ton NO_x removed depending strongly on initial NO_x levels and assumed catalyst life.

Status: SCR has been commercially applied in Japan to over 7000 MW of coal-fired capacity. Extensive pilot work is underway in West Germany in anticipation of installing SCR on over 60,000 MW of coal fired capacity by 1990. Currently, about seven full-scale installations are operating in Germany. All of this existing and planned application is on low sulfur (less than 1%) coal. US utility experience has been limited to EPRI- and EPA-sponsored pilot projects on coal and a 100 MW demonstration on a gas/oil unit at Southern California Edison's Huntington Beach station.

Demonstration Requirements: The most crucial issue affecting the applicability of SCR in the US is the effect of coal sulfur content on the technology's operability. The NO_x reducing catalyst also promotes the conversion of SO_2 to SO_3 which, in combination with excess ammonia, forms a troublesome ammonium sulfate compound which contaminates the fly ash and fouls and plugs the air preheater. The latter may be severe enough to render the plant inoperable. This problem is exacerbated by high SO_2 levels in the flue gas causing increased SO_3 formation,, operation at high NO_x removals, and the deterioration of the catalyst with age. Both pilot- and full-scale development work on high-sulfur US coal is required to determine both the severity of these problems and how they might be resolved.

At least three demonstrations would be required to include coals with a range of properties known to affect catalyst erosion and deactivation and perhaps an additional one to confirm the pilot performance of a low temperature system currently under development in West Germany. These demonstrations, even at modest size (100 - 200 MW), would entail a total cost of $10 to $20 million and require two to four years to obtain a reasonable estimate of catalyst life.

5. FLUIDIZED BED COMBUSTION

a. Atmospheric Fluidized Bed Combustion (AFBC)

Description: AFBC combines emission control of SO_2 and NO_x within the combustion process. A hot bed of limestone particles and coal is fluidized by upflowing air. The limestone calcines and removes approximately 90% of the SO_2 produced resulting in a dry byproduct. The low combustion temperatures (1400-1600°F) result in inherently low NO_x emissions. AFBC can be built at less capital cost (approximately $1300/kW) and produce electricity at lower busbar costs than conventional pulverized coal plants with FGD. These savings are particularly realized at smaller scale (200-300 MW) because of the increased opportunity for modularity and reduced construction time. Fuel flexibility adds an additional cost saving dimension.

Status: The electric utilities have embarked with EPRI on a program to demonstrate AFBC technology by building and operating three utility-size units. Each project will repower an existing generating unit while extending life, improving emissions control and increasing fuel flexibility. In each case the construction period is less than three years.

- A new 160 MW boiler is being built at TVA's Shawnee steam plant near Paducah, Kentucky by TVA, Duke Power, EPRI and State of Kentucky. The boiler will be a bubbling bed type supplied by Combustion Engineering with underbed feed, and will provide steam to the existing turbine/balance-of-plant of unit #10. Startup is scheduled for mid-1988.
- Conversion of an existing 100 MW pulverized coal unit (Black Dog #2) to a 130 MW fluidized bed is under way by Northern States Power Company. The conversion is of the bubbling bed type, supplied by Foster Wheeler and utilizes an overbed feed system. Operation on coal began in June 1986.
- Colorado-Ute Electric Association chose a 100 MW circulating AFB boiler supplied by Pyropower to repower its Nucla generating station. Startup is scheduled for mid-1987.

Demonstration Requirements: The differing types of applications, scopes of supply, timeframes, fuel fired, and locations make the three AFBC demonstration projects complementary in terms of data they will provide to the electric utility industry. These projects will demonstrate the unique features of AFBC technology such as emission control, fuel flexibility, combustion efficiency, and economics.

Four critical factors require resolution during the demonstration phase. The first is the coal and limestone feed system where wet fines plugging, fines carbon loss and high sorbent use need improvement. Second, combustion efficiency can be improved through optimization of excess and secondary air firing. Third, the heat transfer surfaces must be studied to minimize superheater corrosion and stress as well as tube erosion. Finally, the ash removal and particulate control systems require additional evaluation. Assuming successful completion of the demonstrations, AFBC should be ready for broad commercial application in the 1990s.

b. Pressurized Fluidized Bed Combustion (PFBC)

Description: The PFBC process is similar to AFBC except that the combustion system operates under approximately 10 atmospheres of pressure and hence can achieve higher thermal efficiency. An additional advantage of PFBC is that the boiler can be shop fabricated and transported to the power plant site by barge or rail. The PFBC turbocharged boiler, because of its relatively small size, is well suited to space constrained sites and meshes well with the life extension of both oil- and coal-fired units. It is equally applicable to new plants as well as those nearing retirement age. Repowering existing plants with PFBC turbocharged boilers promises the lowest busbar energy cost of any coal based generation expansion option available in the 1990s. SO_2 emissions potential reduction exceeds 90%. NO_x emissions are approximately 0.2-0.3 lb/MBtu or two to three times less than current federal new source standards due to the low combustion temperatures (1300°-1600°F).

Status: Development, both abroad and in the United States, has brought the PFBC turbocharged boiler to the point of readiness for commercial demonstration. Wisconsin Electric Power Company assembled a project team including Foster Wheeler, Brown Boveri, Research Cotrell and EPRI to make this demonstration a reality by 1990 as part of the DOE Clean Coal Demonstration Initiative. Unfortunately, the project was not selected during Phase I and has since been cancelled. Such a demonstration is still needed to provide the critical performance and scale-up data needed to widely apply the PFBC turbocharged boiler in the United States electric utility industry.

American Electric Power Company (AEP) has negotiated a Clean Coal Demonstration Initiative contract with DOE to use PFBC/combined cycle technology to repower the 60 MW Tidd Plant in Brilliant, Ohio. Additional research to analyze the key process variables and development equipment (e.g., the hot gas cleaning system) is being conducted elsewhere, such as at a 30 MW test facility in Grimethorpe, England with both EPRI and DOE support.

Demonstration Requirements: Similar to AFBC, at least three large-scale (100-200 MW) utility demonstrations are required prior to broad commercial application of PFBC. The key factors requiring resolution include those described under AFBC. Further, additional study is required of the high temperature gas cleaning system. For the combined cycle approach, operation of a gas turbine in association with the PFBC boiler requires effective turbine blade shielding and evaluation of integrated operation and control. Total cost of such demonstrations would be approximately $500 million. Assuming the demonstrations initiate in the late 1980s, PFBC could reach commercial readiness by the mid-1990s.

6. COAL GASIFICATION/COMBINED CYCLE (IGCC)

Description: Several different coal gasification processes have been built and operated at lab, pilot, and full-scale throughout the world over the last 50 to 75 years. The technology which has moved furthest toward application in the electric utility industry is the Texaco entrained gasification process. Coal, in dry or slurry form, is exposed to steam, oxygen or air at high pressure (30 atmospheres) producing a synthetic gas. The gas is cooled by generating steam and desulfurized before combustion in a combustion turbine. Heat in the form of steam from the combustion turbine is used to generate additional electricity.

The advantages of IGCC include the ability for phased construction and the extremely low SO_2 and NO_x emissions (approximately 99% sulfur removal and NO_x emissions approximately 10 times less than current requirements). Further, IGCC systems can handle most U.S. coal with little difficulty and have the potential for better thermal efficiencies than a conventional steam cycle.

Status: Until recently, integrated gasification combined cycle (IGCC) power plants have been no more than a "paper promise" to the electric utility industry. However, during the last 10 years, various competitive second generation coal gasification technologies have emerged, including Texaco Partial Oxidation, the British Gas/Lurgi Slagging Gasifier, the Shell Gasification Process, the Kellogg Rust Westinghouse (KRW) fluidized bed and the Allis-Chalmers KilnGas process. All of these technologies are applicable to high-sulfur midwestern and eastern bituminous coal and show their greatest economic benefit operating on these coals.

EPRI is evaluating all of these candidate technologies. The major commitment to date has been to the Texaco Partial Oxidation technology. The culmination of this development program to date is the 100 MWe Cool Water Coal Gasification Combined Cycle Power Plant. The Cool Water project has brought together Southern California Edison Company, Texaco, Inc., the General Electric Company, Bechtel, and a Japanese consortium led by Tokyo Electric Power Company, with EPRI as principals. ESEERCO and SOHIO Alternate Energy are also contributors to the project. This team has funded, developed, designed, constructed, and now operates the world's first truly integrated, commercial-scale coal gasification combined cycle power plant.

Testing on high-sulfur coals and obtaining additional data continues at Cool Water, but the early success has placed this technology at the threshold of acceptance by the U.S. electric utility industry. Presently, more than 10 utilities are conducting or planning site-specific designs based on the

Cool Water experience. These utilities are particularly interested in the phased introduction approach since this provides maximum planning flexibility, and reduces both the front-end financial burden and overall revenue requirements.

Demonstration Requirements: To provide the necessary base for broad commercial use of gasification combined cycle technology, at least three or four additional Cool Water scale demonstrations should be undertaken. Windbox repowering and replacement of an existing boiler with gasification, combustion turbine, and heat recovery steam generator (HRSG) represent areas of additional evaluation. Other factors requiring study include refractory life and heat transfer surface fouling in the gasifier, design conservatisms in the gasifier and gas turbine, the sulfur removal systems (chemical consumption, heat recovery capital cost), costs of the HRSG, and slag disposal.

RESPONSES TO WRITTEN QUESTIONS OF THE SENATE ENERGY COMMITTEE FOLLOWING THE HEARING ON S. 879

MAY 18, 1987
SUBMITTED BY W.S. WHITE, JR.
CHAIRMAN OF
AMERICAN ELECTRIC POWER SERVICE CORPORATION
ON BEHALF OF THE
CLEAN COAL TECHNOLOGY COALITION

1. Critics have argued that additional research on clean coal technologies is not necessary and that clean coal technologies are sufficiently mature for commercialization.

- Please comment on the maturity of various clean coal technologies.

RESPONSE:

The majority of clean coal technologies are projected to have completed the demonstration stage by no later than the mid-1990's. While there are differences of opinion as to exact dates, the Department of Energy's study entitled America's Clean Coal Commitment includes information relevant to this question. That information is attached for the Committee's information and use. (Attachment "A")

- When will they (clean coal technologies) be available for deployment?

RESPONSE:

Even after commercial feasibility is demonstrated (the objective of the current demonstration program), it is still not known when the technology can pass the test of economic viability and long-term reliability which is required of utility plants. The clean coal technology deployment program embodied in S. 879 is the next logical step to accelerate the commercialization of successfully demonstrated technologies and to affirm economic viability and technology reliability. Widespread use would take place after this phase of development which is contemplated to occur as a result of enactment and implementation of S. 879 or similar legislation. Thus, plans for initial "deployment", as envisioned by S. 879, could begin immediately upon completion of the demonstration program, with widespread use of the technology to follow a successful deployment program.

- Please describe those factors which present the most significant technological risks to widespread deployment of clean coal technologies and would require additional research before commercialization would occur. Please provide information on at least the following technologies: advanced physical coal cleaning; furnace injection; duct injection; limestone injection multistage burner; integrated gasification combined-cycle; advanced flue gas desulfurization; gas reburning; atmospheric fluidized bed combustion; and pressurized fluidized bed combustion.

RESPONSE:

The menu of emerging clean coal technologies is quite diverse and each technology may have unique "technological risks" associated with its widespread deployment. In general, however, we can note that a technology must be demonstrated at a sufficiently large scale to offer proof of its long-term reliability under utility operating conditions before it can be accepted by the marketplace.

In written testimony on March 4, 1987 to the Senate Subcommittee on Environmental Protection, Kurt Yeager (Vice President, Coal Combustion Systems Division, Electric Power Research Institute [EPRI]) provided detailed descriptions and status reports, including a discussion of remaining technological risks regarding those technolgies for which you have requested information. These reports have been included for the Committee's information and review. (Attachment "B")

2. How many demonstration projects for each type of technology are necessary to convince potential users -- utilities and industries -- that the technologies are both cost-effective and reliable? How large should these demonstration projects be?

RESPONSE:

The number and size of demonstrations necessary to assure commercialization is technology specific because of the variety of technologies under development and the fact that most clean coal technologies are at different stages in the developmental process. The demonstrations should be at near-commercial or commercial scale to best ensure industry confidence that a successful demonstration can then lead to verification of economic viability and technical reliability as envisioned in a deployment program similar to that contemplated by S. 879.

3. Do the regulatory incentives in the Byrd bill, either together or individually, provide incentives for increased deployment of clean coal technologies?

- what other incentives would provide for the increased deployment of these technologies?

RESPONSE:

The regulatory provisions in S. 879 do provide incentives for utilities and others to undertake clean coal technology deployment projects. S. 879 addresses these regulatory problems associated with the deployment of clean coal technologies.

Additional regulatory changes/incentives that are needed to encourage private investment in clean coal technologies involve, most importantly, the adoption by the states of the regulatory incentives contained in S. 879. Also, uncertainties associated with changes to environmental regulations are very significant. Even the possibility of imposition of further emissions controls is a strong deterrent toward making any commitments that will require substantial funding.

4. What do you believe to be the appropriate role of the states in furthering clean coal technologies? Is there anything that the federal government can do to encourage or influence state support of these technologies.

As stated above, if the states were to adopt regulatory changes/incentives comparable to those made at the federal level under S. 879, it would further encourage private investment in clean coal technologies. Provisions of the Byrd bill, including the rebuttable presumption of prudence at the state level, will help to influence state support of these technologies. Further, S. 879 includes as one of the criteria for selection of deployment projects to receive federal cost sharing the willingness of the state to provide regulatory incentives comparable to those included under S. 879.

In addition to these inducements for the states to encourage the deployment of clean coal technologies, S. 879 directs the Secretary of Energy and the Administrator of the Environmental Protection Agency to explain the regulatory provisions of S. 879 and to encourage coordinated and expedited Federal and State permitting and siting procedures for projects using designated clean coal technologies.

ATTACHMENT "B"

EXCERPT FROM

STATEMENT OF

Kurt E. Yeager
Vice President, Coal Combustion Systems Division
Electric Power Research Institute
Palo Alto, California

PRESENTED BY

Gene G. Mannella
Director, Washington Office
Electric Power Research Institute

BEFORE THE
SUBCOMMITTEE ON ENVIRONMENTAL PROTECTION
SENATE COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

Wednesday, March 4, 1987

1. COAL CLEANING AND UPGRADING

a. Advanced Physical Coal Cleaning

Description: Advanced physical coal cleaning involves four basic operations: (1) fine crushing of all coal cleaned to achieve high pyritic sulfur and ash liberation; (2) use of advanced physical cleaning processes such as microbubble flotation, selective flocculation, true heavy liquid separation, or some combination; (3) use of advanced fine coal physical dewatering technology; and, (4) clean coal agglomeration to produce a handleable product. Advanced physical coal cleaning technology could be combined with conventional cleaning technology in ways that result in cleaning plants that produce multiple fuels of different quality, such as low-sulfur coal for conventional firing and a high-sulfur coal for fluidized bed combustion firing. This technology has the potential to double coal pyritic sulfur removal over currently available cleaning methods from approximately 40% to 80% removal. The estimated ultimate cost of this technology is \$400-600/ton of SO_2 removed including credits associated with utility firing of improved quality coal.

Status:. An EPRI survey identified 25 developmental, physical fine coal cleaning processes. The most promising processes are being evaluated at 1 ton/hour scale under a joint DOE-EPRI project at the EPRI Coal Cleaning Test Facility. This testing program, which is scheduled to run through 1989, will provide the basis for demonstration plant design. EPRI, Ohio Edison, and the Ohio Coal Development Office are evaluating multi-product coal cleaning at a scale of 20 tons/hour. EPRI, DOE, and the Alberta Research Council are developing a desulfurization process based on oil agglomeration. The Central Electricity Generating Board (UK) is developing a dry magnetic coal cleaning process. Several private U.S. companies are developing processes at bench-scale.

Demonstration Requirements: Major developmental issues are process performance, a viable clean coal agglomeration process, and economics. To be considered commercial technology for major U.S. coal types, 5-7 demonstration plants would be required with clean coal capacities on the order of 150 tons/hour. These demonstration plants would involve different advanced physical coal cleaning, dewatering, and agglomeration technologies and different combinations of these technologies with conventional cleaning technology. The estimated cost of a typical demonstration project (3-5 year duration) is \$40-60 million.

b. Low-Rank Coal Upgrading

Description: Low-rank coal upgrading processes produce a high-Btu, low-sulfur, low-moisture, low-ash fuel by thermally removing moisture and, in some processes, sulfur and/or ash from subbituminous coal or lignite. To produce a product with handleability and storability comparable to high quality bituminous coal, coal particle surfaces are altered during upgrading, or subsequent to it, to reduce moisture re-absorption. These processes can potentially produce compliance coal (less than 1.2 lbs SO_2/MBtu) from many western coals and lignite. Estimated upgraded coal cost is $30-40/ton, f.o.b. plant.

Status: Western Energy, Amax Coal, K-Fuel, ARCO, Mobil, Bechtel, the University of North Dakota Energy Research Center, and others are developing upgrading processes. Western Energy is operating a 200 lb/hour pilot plant and has proposed to build a demonstration plant under the Federal Clean Coal Program. K-Fuel is operating a 500 lb/hour pilot plant and is planning a 100 ton/hour demonstration plant in the Powder River Basin. Several major western coal producers have announced plans for coal or lignite upgrading projects.

Demonstration Requirements: Major development issues are ultimate product quality and economics. To determine which of the competing technologies are commercially viable and account for coal and lignite processing differences, 3-5 demonstration plants with upgraded capacities on the order of 150 tons/hour would be required. The estimated cost of a typical low rank coal upgrading demonstration project (3-5 year duration) is $40-50 million.

2. WET FGD

a. Advanced Conventional FGD

Description: Improvements in conventional FGD can be illustrated using three examples. First, process improvements such as the jet bubbling reactor used in the Bechtel CT-121 Process; second, application of spray drying to high sulfur coal; and third, an advanced, conventional limestone FGD system producing gypsum with no reheat and no redundant modules for use at compact sites. Each of these designs can achieve 90 to 95% SO_2 control. The cost and performance advantages are a 20-50% capital cost savings and 20-40% operating cost savings over conventional FGD systems available today. The jet bubbling reactor and advanced limestone/gypsum designs can both make wallboard grade gypsum for sale or disposal. Capital costs for such systems will vary depending on a number of factors such as fuel sulfur content and unit size. Typical retrofit cost for a 200 MW unit burning medium to high sulfur coal (2.5% to 4%) is about $200-$300/kW.

Status: Several advanced conventional FGD processes are being or have been tested at large pilot and commercial scale. The CT-121 process has been piloted on high sulfur coal at 23 MW by EPRI and is operating in Japan on 3% sulfur coal at 250 MW. A 40 MW industrial unit will be tested in 1987 by EPRI and the State of Illinois. Bechtel is attempting to sell a commercial utility unit; EPRI would test the unit's performance which is planned to occur in 1989-1990.

The high sulfur coal spray drying designs adapt the successful concept currently used on 7000 MW of low sulfur coal capacity. Two pilot plants are currently starting operation to test performance on high sulfur coal. TVA, Ontario Hydro, and EPRI are testing a 10 MW spray dryer/ESP combination at Shawnee, and EPRI is testing a 4 MW spray dryer fabric filter at the High Sulfur Test Center near Buffalo. Testing should be complete in 1989. A full-scale 160 MW demonstration of a high sulfur spray dryer/fabric filter has been proposed by TVA for funding under Phase II of the Clean Coal Technology program with testing to be completed in 1991.

Advanced conventional FGD systems using limestone and producing a salable gypsum byproduct with no spare modules, no stack gas reheat and gypsum byproduct sales have not been demonstrated at pilot or full scale in the U.S. EPRI will pilot test these improvements at the High Sulfur Test Center at 4 MW. New York State Electric and Gas has proposed testing this system at 168 MW as part of the Phase II Clean Coal Technology program concluding in 1989-1990.

Demonstration Requirements: Issues requiring resolution include: finding suitable commercial sites for demonstrations of advanced processes such as CT-121 and providing risk cost sharing for the work; establishing the performance and cost associated with high sulfur spray drying; and establishing the reliability and performance of a simplified advanced limestone FGD system producing gypsum. For these example systems, the number of demonstrations desirable to reach commercial acceptance include two jet bubbling reactor systems - one using a prescrubber and one without; two high sulfur spray drying demonstrations, one with an ESP and one with a fabric filter; and two advanced limestone systems with different absorber oxidation tank arrangements. Each demonstration should be at least 100 MW in size using at least 3% sulfur content coal. Total costs for these demonstrations is approximately $140 million.

b. Advanced Regenerable FGD

Description: Advanced regenerable FGD systems can use diverse physical and chemical principals, but generally recover sulfur byproducts as concentrated SO_2, sulfuric acid, or elemental sulfur. Three SO_2 or SO_x/NO_x processes illustrate the development status of advanced regenerable FGD processes. One process combines a conventional sodium based scrubber with electrolytic regeneration of the scrubbing solution using a bipolar membrane (e.g., SOXAL). Another process uses dry activated carbon (char) pellets to adsorb SO_2, with NH_3 injection to remove limited amounts of NO_x (e.g., Mitsui). A third process removes SO_2 and NO_x by chemisorption in a surface layer of sodium carbonate deposited on a gamma-alumina substrate (e.g., NOXSO). The sodium scrubbing process can remove over 95% of the SO_2 but no NO_x. The activated carbon process can remove over 95% of the SO_2 and 40%-60% of the NO_x. The chemisorption process can remove about 90% SO_2 and 90% NO_x. The processes are more capital intensive than throw-away FGD (approximately $300-400/kW for regenerable systems versus $200-300/kW for a comparable gypsum system), but are projected to be competitive in levelized cost (approximately $600/ton SO_2 removed). The major advantage is in elimination of waste disposal costs.

Status: The advanced regenerable FGD processes are currently at small pilot scale with the exception of activated carbon process which has a 100 MW prototype operating on low sulfur coal in Japan. The sodium scrubbing process is being tested at small pilot scale (0.4 MW in Canada) and will soon be tested at 0.4 MW at EPRI's High Sulfur Test Center. A full-scale test has been proposed at an Illinois power plant in response to the Phase II Clean Coal Technology program. The chemisorption process has undergone pilot development in Japan, and is operating at the Omuta station of Mitsui Aluminum on a 100 MW base load coal-fired boiler. The process has been tested on a 50 acfm slip stream at TVA's Shawnee station and, more recently, at 1 MWe equivalent at DOE's PETC facilities. Additional tests are planned at this scale through 1987.

Demonstration Requirements: All of these systems require full-scale prototype testing on U.S. coals to verify system performance and costs and establish that they are competitive with conventional FGD. The issues regarding sodium scrubbing are whether the membranes can tolerate small amounts of flyash contamination, and whether optimized system operation will result in competitive economics. The activated carbon process issues include sorbent attrition and controlling dust emissions from the char. The chemisorption process issues include sorbent attrition, materials choice, and reducing gas use for regeneration.

The demonstrations required to ready these processes for the commercial market include: 2 sodium scrubbing process demos - one producing liquid SO_2 and one using off-peak power for regeneration; one activated carbon process demo on high sulfur U.S. coal; and two chemisorption process demonstrations, one aimed at moderate (50%) NO_x removal and one aimed at 90% NO_x removal. Each demonstration should be at least 100 MW in size using at least 3% sulfur content coal. Total costs for these demonstrations would be approximately $180 million.

3. DRY SO_2 CONTROL

a. Furnace Sorbent Injection

Description: Furnace sorbent injection (FSI) refers to the injection of calcium-based sorbents (lime or limestone) into the radiant zone of the furnace where it calcines and then reacts to form $CaSO_4$ in the 2300-1600°F temperature range. The sulfated sorbent is then collected along with the fly ash in the precipitator or baghouse. An alternate process, convective pass injection (CPI), is a similar process in which the sorbent is injected near the economizer at approximately 1000°F.

SO_2 removal for FSI is a function of sorbent choice and quantity injected but is typically 35-45% with limestone and 50-60% with lime at injection rates corresponding to calcium to sulfur ratios of two. The process is characterized by low capital costs (approximately $50/kW), simplicity of design and operation, and costs which are about $200 - $500/ton of SO_2 removed lower than those typical of wet FGD. CPI performance and costs are presently comparable to those for FSI. The lower temperatures at the injection location and the extremely fast reaction rates hold promise of performance improvements using enhancement techniques which are inapplicable at FSI temperatures.

Status: FSI is being demonstrated at full-scale at two U.S. power plants: (1) Ohio Edison's Edgewater Plant by USEPA, USDOE, the State of Ohio, and others; and (2) Richmond Power and Light's Whitewater Valley station by EPRI and USEPA following extensive pilot scale development by EPRI and EPA. Several smaller scale industrial demonstrations in the US and utility demonstrations in Canada and Western Europe have been successfully completed.

CPI is still in the bench and pilot-scale development stage, although limited full-scale tests of an unoptimized system at Saskatchewan Power's Boundary Dam plant suggest that pilot results can be achieved in practice.

Demonstration Requirements: Although FSI is furthest developed of the several dry SO_2 control technologies, full-scale demonstration is needed to resolve potentially adverse impacts on plant operations. These include fouling of convective pass heat transfer surfaces in the furnace, excessive particulate emissions, and solid waste management and disposal problems resulting from increased by-product quantities and the high reactivity of the unreacted sorbent. In addition, methods must be explored to reduce sorbent use and costs through sorbent recycle, downstream humidification, or supplemental duct injection to extend the range of units for which the technology would be economical.

Two or three additional demonstrations beyond those two currently underway should include application to a cyclone unit with high flue gas quench rates and application of sorbent injection in combination with reburning for NO_x control. Two such demonstrations are planned as part of the DOE Phase I Clean Coal Technology program to be conducted in Illinois with support of the state of Illinois, the Gas Research Institute, and the city of Springfield. Additional projects were proposed in the DOE Phase II solicitation including a comprehensive cyclone demonstration in Wisconsin. The demonstrations should be complete by early 1990 at a cost of approximately $30 million.

b. Duct Sorbent Injection

Description: Duct sorbent injection refers to those processes where the sorbent is injected into low temperature flue gas downstream of the air preheater. SO_2 removal can be accomplished with either sodium- or calcium-based sorbents. In the case of calcium-based sorbents, it is necessary to humidify the flue gas to within 40-20°F of the saturation temperature in order to achieve sufficiently high reaction rates for economical SO_2 capture. This can be accomplished either through separate humidification followed by dry sorbent injection or through slurry injection in the case of in-duct spray drying.

As with furnace sorbent injection, these processes are characterized by moderate sulfur capture (40 to 70% SO_2 removal), simplicity of design and operation, low capital cost and attendant savings in levelized removal costs. Several varieties of the basic technology are possible including in-duct spray drying using a slurry, dry duct injection using sodium or calcium sorbents, and a hybrid system which includes retrofit of a fabric filter after the existing ESP. In the latter, a dry calcium sodium sorbent is injected into the clean gas stream following the ESP. All have capital costs of about $50/kW with the exception of the hybrid system which is about $100/kW due to addition of the baghouse. However, the latter is potentially capable of about 70 percent SO_2 removal (versus about 40-50% for the others) resulting in a cost effectiveness of about $600-650/ton of SO_2 removal making it an attractive alternative to other dry systems.

Status: Table A-1 summarizes the stage of development for each process, the important development projects currently underway in the US, and the important issues to be resolved prior to commercial availability. Each of the processes for which pilot-scale development is successful will require full-scale demonstration to resolve operating issues such as particulate control, waste management and disposal, and the severity of duct deposition, plugging, and corrosion.

Demonstration Requirements: As indicated in Table A-1, the dominant issue for all of the calcium-based processes is humidification and whether it can be achieved without unacceptable duct deposition or precipitator degradation. It is likely that as many as a dozen demonstrations will be required to cover the range of processes, coals, and particulate controls. Several of these demonstrations may be combined with FSI demos currently underway at Edgewater and Richmond. The demonstrations could be completed by 1992-3 at a cost of $2 to $4 million each.

4. NO_x CONTROL

a. Combustion Modification

Description: Combustion modification achieves NO_x reductions through the redesign of burners or through rearrangement of the fuel and air flows to the furnace (such as overfire air or reburning) in order to control the mixing of the fuel and air in relationship to the local temperature patterns. Maintenance of fuel rich conditions in the primary flame zone followed by gradual air addition later in the combustion process minimizes NO_x formation. Reburning involves the redirection of 10-20% of the total fuel to the mid-furnace region to create a zone for reduction of NO_x formed in the primary burner zone. Such methods are applicable to oil and gas units as well as coal.

Achievable reductions are typically 40-60% although a combination of methods (low NO_x burners followed by reburning, for example) may achieve 75-80% reduction over uncontrolled emissions in some cases. Capital costs for retrofit low NO_x burners are estimated at $5 to $10/kW with

TABLE A-1
DRY SO_2 CONTROL
DUCT INJECTION

Process	Stage Development	Projects	Development Issues	
Duct Injection Sodium	Commercial	100 MW demo (R.D. Nixon/EPRI)		o Soluble waste o NO_2 plume o Sorbent cost/ availability in East
Duct Injection Calcium	Pilot (1-5 MW) Demo (- 100 MW)	EPRI-Arapahoe DOE-Ohio Edison EPA-Edgewater EPRI-EPA-Richmond EPRI/Util.-Brayton Point W. Europe Demos	Humidification Particulate Control Waste Management	o Duct Deposition
In-Duct Spray Drying	Pilot (1-5 MW)	EPRI-Arapahoe DOE/Bechtel-Consumers DOE/GEESI-AEP		o Duct Deposition
HYPAS	Pilot (4 MW)	EPRI-HSTC		o Baghouse Performance
FSI	Demo (100 MW)	EPA/DOE-Edgewater EPRI/EPA-Richmond Canadian Utilities W. Europe Demos		o Boiler impacts o Reactive waste
CPI	Lab/pilot (25 MW) field	EPRI-Lab scale EPRI/DOE (proposal) Saskatchewan Power/EPRI		o Sorbent performance

no additional operating costs expected. Reburning costs depend on the choice of reburning fuel (gas, oil, or coal) with capital costs ranging from \$20 to \$35/kW and operating costs dominated by fuel cost differentials from the base coal costs.

Status: Combustion modification has been widely applied at full scale on new units to meet NSPS on coal-fired utility boilers and for both new unit and retrofit applications on oil- and gas-fired units. Pilot development of retrofit approaches to coal units has progressed to the point where technologies are ready for demonstration on three major categories of existing boilers (tangentially-fired, wall-fired with circular burners, and cell burners). A full-scale demonstration (350 MW) of the PM (pollution minimization) burner on a tangentially-fired unit is now underway at KPL Gas Service's Lawrence Energy Center Unit #5. Sponsors include EPRI, KPL, Combustion Engineering, and the Kansas Electric Utilities Research Program. Burner installation will occur Spring 1987 and the demonstration period is one year. A wall-fired demonstration is planned for Homer City Unit 1 or Unit 2 (650 MW) in mid-1988. Pilot work is underway at Babcock & Wilcox on reburning for specific application to cyclone units under EPRI/GRI sponsorship.

Demonstration Requirements: Remaining development requirements are primarily related to questions of operability. These include demonstrating that NO_x reductions can be achieved without adverse effects on carbon burnout, furnace efficiency, flame stability, slagging or corrosion. In addition to the planned demonstrations of low NO_x burners, systems combining reburning with these burners on tangentially-fired and wall-fired units are needed. Several candidate demonstration projects have been submitted to USDOE in Phase II of the Clean Coal Technology submissions. Three to five additional demonstrations could be completed by 1992-3 covering all categories of pre-NSPS units, including the promising combined systems. Based on experience to date, these demonstrations would cost from \$2 to \$4 million each.

b. Post-Combustion NO_x Control

Description: Post-combustion NO_x control refers to flue gas treatment methods for conversion or removal of NO_x species external to the furnace. The most common processes involve the injection of ammonia or ammonia-like compounds (urea, isocyanic acid) into the flue gas with or without a catalyst to promote the reduction of NO_x to nitrogen and water vapor. The most extensively developed process is selective catalytic reduction (SCR) in which ammonia is injected into the flue gas at about 800°F in the presence of a vanadium pentoxide catalyst.

NO_x reductions of 80% or more are possible with SCR alone and, if used in conjunction with a low-NO_x burner achieving 50% initial reduction, a combined efficiency of 90% can be obtained. Costs are high, at $75 to $100/kW, and removal costs are estimated at $4000 to $8000/ton NO_x removed depending strongly on initial NO_x levels and assumed catalyst life.

Status: SCR has been commercially applied in Japan to over 7000 MW of coal-fired capacity. Extensive pilot work is underway in West Germany in anticipation of installing SCR on over 60,000 MW of coal fired capacity by 1990. Currently, about seven full-scale installations are operating in Germany. All of this existing and planned application is on low sulfur (less than 1%) coal. US utility experience has been limited to EPRI- and EPA-sponsored pilot projects on coal and a 100 MW demonstration on a gas/oil unit at Southern California Edison's Huntington Beach station.

Demonstration Requirements: The most crucial issue affecting the applicability of SCR in the US is the effect of coal sulfur content on the technology's operability. The NO_x reducing catalyst also promotes the conversion of SO_2 to SO_3 which, in combination with excess ammonia, forms a troublesome ammonium sulfate compound which contaminates the fly ash and fouls and plugs the air preheater. The latter may be severe enough to render the plant inoperable. This problem is exacerbated by high SO_2 levels in the flue gas causing increased SO_3 formation,, operation at high NO_x removals, and the deterioration of the catalyst with age. Both pilot- and full-scale development work on high-sulfur US coal is required to determine both the severity of these problems and how they might be resolved.

At least three demonstrations would be required to include coals with a range of properties known to affect catalyst erosion and deactivation and perhaps an additional one to confirm the pilot performance of a low temperature system currently under development in West Germany. These demonstrations, even at modest size (100 - 200 MW), would entail a total cost of $10 to $20 million and require two to four years to obtain a reasonable estimate of catalyst life.

5. FLUIDIZED BED COMBUSTION

a. Atmospheric Fluidized Bed Combustion (AFBC)

Description: AFBC combines emission control of SO_2 and NO_x

within the combustion process. A hot bed of limestone particles and coal is fluidized by upflowing air. The limestone calcines and removes approximately 90% of the SO_2 produced resulting in a dry byproduct. The low combustion temperatures (1400-1600°F) result in inherently low NO_x emissions. AFBC can be built at less capital cost (approximately $1300/kW) and produce electricity at lower busbar costs than conventional pulverized coal plants with FGD. These savings are particularly realized at smaller scale (200-300 MW) because of the increased opportunity for modularity and reduced construction time. Fuel flexibility adds an additional cost saving dimension.

Status: The electric utilities have embarked with EPRI on a program to demonstrate AFBC technology by building and operating three utility-size units. Each project will repower an existing generating unit while extending life, improving emissions control and increasing fuel flexibility. In each case the construction period is less than three years.

- A new 160 MW boiler is being built at TVA's Shawnee steam plant near Paducah, Kentucky by TVA, Duke Power, EPRI and State of Kentucky. The boiler will be a bubbling bed type supplied by Combustion Engineering with underbed feed, and will provide steam to the existing turbine/balance-of-plant of unit #10. Startup is scheduled for mid-1988.
- Conversion of an existing 100 MW pulverized coal unit (Black Dog #2) to a 130 MW fluidized bed is under way by Northern States Power Company. The conversion is of the bubbling bed type, supplied by Foster Wheeler and utilizes an overbed feed system. Operation on coal began in June 1986.
- Colorado-Ute Electric Association chose a 100 MW circulating AFB boiler supplied by Pyropower to repower its Nucla generating station. Startup is scheduled for mid-1987.

Demonstration Requirements: The differing types of applications, scopes of supply, timeframes, fuel fired, and locations make the three AFBC demonstration projects complementary in terms of data they will provide to the electric utility industry. These projects will demonstrate the unique features of AFBC technology such as emission control, fuel flexibility, combustion efficiency, and economics.

Four critical factors require resolution during the demonstration phase. The first is the coal and limestone feed system where wet fines plugging, fines carbon loss and high sorbent use need improvement. Second, combustion efficiency can be improved through optimization of excess and secondary air firing. Third, the heat transfer surfaces must be studied to minimize superheater corrosion and stress as well as tube erosion. Finally, the ash removal and particulate control systems require additional evaluation. Assuming successful completion of the demonstrations, AFBC should be ready for broad commercial application in the 1990s.

b. Pressurized Fluidized Bed Combustion (PFBC)

Description: The PFBC process is similar to AFBC except that the combustion system operates under approximately 10 atmospheres of pressure and hence can achieve higher thermal efficiency. An additional advantage of PFBC is that the boiler can be shop fabricated and transported to the power plant site by barge or rail. The PFBC turbocharged boiler, because of its relatively small size, is well suited to space constrained sites and meshes well with the life extension of both oil- and coal-fired units. It is equally applicable to new plants as well as those nearing retirement age. Repowering existing plants with PFBC turbocharged boilers promises the lowest busbar energy cost of any coal based generation expansion option available in the 1990s. SO_2 emissions potential reduction exceeds 90%. NO_x emissions are approximately 0.2-0.3 lb/MBtu or two to three times less than current federal new source standards due to the low combustion temperatures (1300°-1600°F).

Status: Development, both abroad and in the United States, has brought the PFBC turbocharged boiler to the point of readiness for commercial demonstration. Wisconsin Electric Power Company assembled a project team including Foster Wheeler, Brown Boveri, Research Cotrell and EPRI to make this demonstration a reality by 1990 as part of the DOE Clean Coal Demonstration Initiative. Unfortunately, the project was not selected during Phase I and has since been cancelled. Such a demonstration is still needed to provide the critical performance and scale-up data needed to widely apply the PFBC turbocharged boiler in the United States electric utility industry.

American Electric Power Company (AEP) has negotiated a Clean Coal Demonstration Initiative contract with DOE to use PFBC/combined cycle technology to repower the 60 MW Tidd Plant in Brilliant, Ohio. Additional research to analyze the key process variables and development equipment (e.g., the hot gas cleaning system) is being conducted elsewhere, such as at a 30 MW test facility in Grimethorpe, England with both EPRI and DOE support.

Demonstration Requirements: Similar to AFBC, at least three large-scale (100-200 MW) utility demonstrations are required

prior to broad commercial application of PFB
factors requiring resolution include those de
AFBC. Further, additional study is required
temperature gas cleaning system. For the comb
approach, operation of a gas turbine in associa
PFBC boiler requires effective turbine blade sh
evaluation of integrated operation and control.
of such demonstrations would be approximately $5
million. Assuming the demonstrations initiate in
1980s, PFBC could reach commercial readiness by t
1990s.

6. COAL GASIFICATION/COMBINED CYCLE (IGCC)

Description: Several different coal gasification pro
have been built and operated at lab, pilot, and full-s
throughout the world over the last 50 to 75 years. Th
nology which has moved furthest toward application in t
electric utility industry is the Texaco entrained gasifi
tion process. Coal, in dry or slurry form, is exposed t
steam, oxygen or air at high pressure (30 atmospheres)
producing a synthetic gas. The gas is cooled by generati
steam and desulfurized before combustion in a combustion
turbine. Heat in the form of steam from the combustion
turbine is used to generate additional electricity.

The advantages of IGCC include the ability for phased construction and the extremely low SO_2 and NO_x emissions (approximately 99% sulfur removal and NO_x emissions approximately 10 times less than current requirements). Further, IGCC systems can handle most U.S. coal with little difficulty and have the potential for better thermal efficiencies than a conventional steam cycle.

Status: Until recently, integrated gasification combined cycle (IGCC) power plants have been no more than a "paper promise" to the electric utility industry. However, during the last 10 years, various competitive second generation coal gasification technologies have emerged, including Texaco Partial Oxidation, the British Gas/Lurgi Slagging Gasifier, the Shell Gasification Process, the Kellogg Rust Westinghouse (KRW) fluidized bed and the Allis-Chalmers KilnGas process. All of these technologies are applicable to high-sulfur midwestern and eastern bituminous coal and show their greatest economic benefit operating on these coals.

EPRI is evaluating all of these candidate technologies. Th
major commitment to date has been to the Texaco Partial
Oxidation technology. The culmination of this development
program to date is the 100 MWe Cool Water Coal Gasificatio
Combined Cycle Power Plant. The Cool Water project has
brought together Southern California Edison Company, Texac

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Inc., the General Electric Company, Bechtel, and a Japanese consortium led by Tokyo Electric Power Company, with EPRI as principals. ESEERCO and SOHIO Alternate Energy are also contributors to the project. This team has funded, developed, designed, constructed, and now operates the world's first truly integrated, commercial-scale coal gasification combined cycle power plant.

Testing on high-sulfur coals and obtaining additional data continues at Cool Water, but the early success has placed this technology at the threshold of acceptance by the U.S. electric utility industry. Presently, more than 10 utilities are conducting or planning site-specific designs based on the Cool Water experience. These utilities are particularly interested in the phased introduction approach since this provides maximum planning flexibility, and reduces both the front-end financial burden and overall revenue requirements.

Demonstration Requirements: To provide the necessary base for broad commercial use of gasification combined cycle technology, at least three or four additional Cool Water scale demonstrations should be undertaken. Windbox repowering and replacement of an existing boiler with gasification, combustion turbine, and heat recovery steam generator (HRSG) represent areas of additional evaluation. Other factors requiring study include refractory life and heat transfer surface fouling in the gasifier, design conservatisms in the gasifier and gas turbine, the sulfur removal systems (chemical consumption, heat recovery capital cost), costs of the HRSG, and slag disposal.

AMERICA'S CLEAN COAL COMMITMENT

A REPORT BY THE
U.S. DEPARTMENT OF ENERGY

FEBRUARY 1987

AMERICA'S CLEAN COAL COMMITMENT

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Prepared by the
Office of Fossil Energy
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C.   20585

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Preface

America's commitment to a quality environment -- in terms of both national policy and financial investment -- is unmatched by any nation on this globe. That fact has often been lost amid the intense debate that has characterized the "acid rain" issue in the 1980s. This has been particularly true when the debate centered on the role of coal in meeting the nation's energy and environmental objectives. America's coal industry -- both producers and users -- has often been portrayed as reluctant to invest in new technology that could improve environmental quality and provide more efficient, economical service to consumers.

The record shows, however, that America's investment in a cleaner environment is substantial. The initial section of this report draws on previously published data to document the fact that U.S. coal-burning electric utilities *alone* have committed more than $60 *billion* during the last decade to meet a set of sulfur dioxide reduction standards that are among the most stringent in the world. The report also illustrates the results of that investment -- namely cleaner air.

The document then describes a more recent example of America's commitment to a quality environment -- the national effort to develop and demonstrate a new slate of more efficient and cleaner coal-based technologies. Here too, as illustrated by the data in this report, the U.S. stands second to none in its commitment to an environmentally clean energy future powered, in large part, by our most abundant energy resource, coal.

America's clean coal commitment in the 1980s is truly a national effort whose participants include not only the federal government but farsighted State governments and innovative entrepreneurs in the private sector. In these terms, as this report shows, America's clean coal technology commitment amounted to approximately $1.6 *billion* in expenditures between 1980 and 1985 and is expected to total an additional $6 *billion* in anticipated technology development and demonstrations between 1985 and 1992.

America is determined to become the "world's showcase" of new clean coal technology. In addition to accelerating our environmental progress here at home, new clean coal options can help strengthen the common bonds of cooperation with our international neighbors and provide new articles of trade.

America's commitment to new coal technology began in hundreds of research laboratories in the 1960s and 70s. Today the development pace has quickened and new concepts are moving out of those laboratories and over the commercial threshold. This report, we believe, will serve as an accounting of this national commitment.

John S. Herrington

John S. Herrington
Secretary of Energy

Executive Summary

America's Clean Coal Commitment illustrates the national investment being made, particularly by the power generating industry, to improve the quality of the nation's air while increasing the use of America's most abundant fossil energy resource, coal. This investment takes on two forms: (1) the financial response of the utility industry to the requirements of the 1970 Clean Air Act, and (2) the recent expansion of efforts across the nation to develop and demonstrate a new generation of innovative clean coal technologies.

The Nation has made a major investment in pollution control.

Passage of the Clean Air Act and its subsequent amendments set America on a course that committed billions of dollars to environmental protection. Since enactment of the legislation in 1970, estimates by the Environmental Protection Agency are that U.S. industry has spent well over $225 billion to control air emissions.

A major part of this expenditure has been made by the electric utility industry, particularly those utilities that generate power from coal. Since 1975 (through 1985), the nation's utilities have spent more than $60 *billion* for sulfur dioxide (SO_2) capture alone. These expenditures were made on the only three options that were available during this timeframe for controlling SO_2:

Flue gas scrubbing -- a chemical process that removes large amounts of SO_2 from coal combustion gases before they are released to the atmosphere. Approximately $17 billion was expended to install and operate flue gas scrubbers on power plants between 1975 and 1985.

Coal cleaning -- a pre-combustion process that removes a portion of the sulfur and other impurities in coal typically through physical separation techniques. In the 1975 to 1985 timeframe, approximately $11 billion in coal washing costs were incurred to clean about 35% of the coal consumed by electric utilities.

Coal switching -- the substitution of a typically higher priced, lower sulfur coal in a power plant that previously burned high sulfur coal. The nation's coal-burning electric utilities paid approximately $34 billion in premiums for low-sulfur coal from 1975 to 1985.

The investment is paying off -- sulfur emissions are down.

As a result of the expenditures made to control air pollution, the nation's air is cleaner today than it has been in the last decade. Sulfur dioxide (SO_2) emissions have declined dramatically. Since the present Clean Air Act was passed in 1970, SO_2 emissions from all U.S. sources have dropped about 23% from their peak in 1973. Coal-fired power plants nationwide have reduced their SO_2 emissions by 11.4% from their peak in 1977 to the present. This has occurred even as coal consumption was increasing dramatically. From 1973 to 1985, while nationwide sulfur emissions were on their way down, the use of coal by America's electric utilities was *increasing* by 78%, from 389 million tons per year to 693 million tons per year.

Sulfur emissions reductions from coal-fired power plants in the northeastern quadrant of the U.S. -- the region receiving the most attention in the acid rain debate -- have been even more dramatic, dropping by 19% from 1975 to 1984 even as coal consumption in this region increased 23 percent.

These emission reductions, however, tell only a part of the story. If the national investment in emission control had *not* been made and the amount of sulfur dioxide released for each unit of coal burning in 1985 had remained the same as in 1975, the nation's coal-fired power plants would today be releasing 28.9 million tons of SO_2 annually into the atmosphere rather than 15.6 million tons -- an 85% increase.

In contrast to sulfur emissions, releases of nitrogen oxides (NO_x), another suspected acid rain causing pollutant, have held relatively constant since 1975.

Additional sulfur emission reductions pose severe difficulties for conventional controls

Reducing air emission even further using the techniques of the 1970s and early 1980s would pose severe problems due to the limitations of conventional technology. For example:

Conventional *coal cleaning* has only a limited ability to remove sulfur impurities, typically only 10% to 30% of the total sulfur in coal. *Flue gas scrubbing* is very costly and can be applied only to plants that have the available space requirements. To operate, scrubbers must consume a portion of the power plant's energy, thereby lowering efficiency, and today's typical systems produce massive amounts of a pasty waste product that is difficult to handle. *Coal switching* is also very costly not only in terms of the premium that must be paid to purchase and transport lower sulfur coal but also in the social disruptions that would result from major shifts in supply sources.

The Nation's population of coal-fired plants is diverse and widely dispersed.

The limitations of conventional controls are compounded by the wide diversity of the nation's utility boiler population in terms of boiler designs, ages, sizes, etc., as well as the type of coal consumed. Each of these factors can limit the effectiveness in applying any of the three conventional emission control options -- coal cleaning, flue gas scrubbing or coal switching.

If further emission reductions are to be achieved without incurring great costs or dislocations, innovative technologies will be needed that are less sensitive to fuel type and that can retain acceptable economics over a wide range of boiler sizes and types.

Many of these new technologies also offer the advantage of significant NO_x control, something that the conventional SO_2 control options can't achieve. And all produce an easily disposed of or, in some cases, a useable waste product.

Significant opportunities exist for new clean coal technologies because of past expenditures and a national commitment to future support.

For the last decade, the U.S. has been pursuing opportunities to develop advanced clean coal technologies. A solid technical foundation now exists, and using it, the nation has begun to embark on a major expansion of clean coal technology development and demonstration.

Innovative clean coal technologies can generally be grouped into two categories: (1) *retrofit technologies* which can be used on existing plants to reduce emissions, and (2) *repowering technologies* that replace a significant portion of the original plant and often increase capacity while reducing emissions.

These emerging technologies offer significant improvements in cost-effective environmental performance, compared to previous alternatives. For example, advanced physical coal cleaning can potentially reduce SO_2 emissions by 65%, more than double the effectiveness of conventional techniques, and chemical and microbial cleaning may boost that effectiveness to 90% or more.

Retrofit techniques such as the limestone injection multistage burner, slagging combustors, gas reburning, in-duct sorbent injection, and advanced flue gas cleanup, used separately or in combinations, can control both SO_2 and NO_x and produce an environmentally safe waste product. Although the sulfur emission reduction potentials of some of these technologies are lower than conventional flue gas scrubbing, the reduction levels will likely be sufficient to meet possible future requirements for existing plants.

Repowering technologies, such as integrated gasification combined cycle (IGCC) and fluidized bed combustion (FBC) are able to reduce both SO_2 and NO_x emissions. In the case of IGCC, sulfur emission reductions greater than 99% have been achieved, while pressurized FBC is capable of lowering sulfur emissions by 95%. IGCC technologies can also reduce NO_x emissions by 40% compared to a conventional coal-fired power plant, while pressurized FBC technologies can achieve a NO_x reduction of up to 85%.

Many of these retrofit and repowering options are in the demonstration stage today. They will be technologically available either in the late 1980s or early 1990s.

In addition to improved environmental performance, the new clean coal technologies, particularly repowering concepts, also offer substantial technical and economic benefits. Repowering an existing power station, with IGCC for example, can improve its efficiency from a nominal 35% to as much as 40% and increase its power output by up to 150%. This boost in power production offsets most of the capital costs of refurbishing an aging plant, thereby resulting in only a minimal impact on the cost of electricity.

The Nation has built a solid R&D foundation for clean coal technologies.

America's commitment to clean coal technologies began in hundreds of research laboratories and test sites in the 1960s and 70s. In the aftermath of the 1973 oil embargo, the U.S. coal research program was driven largely by a goal of displacing liquid and gaseous fuels. Beginning in 1980, however, the program began to concentrate more on innovative technologies that could control SO_2 and NO_x. The principal motivation in the decade of the 1980s has been to address growing concerns about environmental issues, such as acid rain, and the compatibility of increased coal use with the nation's environmental goals.

From 1980 to 1985, the U.S -- through both public and private financing -- spent approximately $3.2 billion on the development of new coal technologies. Of this, the research, development and demonstration of new coal-based technologies to control SO_2 and NO_x accounted for more than $1.6 billion.

The progress made as a result of these expenditures provide the technological basis for proceeding with full-scale demonstrations of promising new clean coal technologies.

The U.S. is rapidly becoming the world's showcase for clean coal technology.

America's clean coal commitment is a national effort involving the federal government, state governments and private sponsors. Between 1986 and 1992, the nation will likely invest more than *$6 billion* to develop and demonstrate the emerging new generation of clean coal concepts.

Slightly more than $2 billion of this funding will be provided by the federal government. Nearly double that -- $3.86 billion -- will be invested by private sources. Two States alone, Illinois and Ohio, are expected to commit more than $300 million.

Approximately 80%, or $4.9 billion of the $6 billion, will be committed to specific field projects that are intended to demonstrate the large-scale viability of these new technologies. The remainder is comprised of privately and publicly financed research and development programs that are focused specifically on the cleaner use of U.S. coal.

The Nation is meeting its commitment to a cleaner environment in concert with increasing the use of American coal.

Coal's abundance (80% of the nation's known fossil fuel resources) makes it one of America's most important strategic resources in building a more secure energy future. Coal can be one of the nation's most productive domestic energy sources well into the 21st Century and beyond. If coal is to reach its full potential, however, economically competitive, advanced coal-using systems must be developed which are sensitive to diverse energy markets and site-specific factors as well as stringent environmental requirements.

America's clean coal commitment has the potential to:

1. Control large amounts of the SO_2 and NO_x released from coal-fired power plants including those in the environmentally-sensitive Northeast.
2. Return economic benefits to American consumers by permitting clean energy to be generated without financially constraining capital investments for environmental controls.
3. Retrofit and repower aging coal-fired power plants, particularly those in the East.
4. Use high-sulfur coals, thereby avoiding the social disruptions associated with massive coal switching, and
5. Reduce acid rain related emissions -- especially from aging power plants in the nation's northeast quadrant.

How rapidly these innovative clean coal technologies will be deployed depends upon many factors. Two of the most important are (1) technology risk -- concern about the performance and reliability of the technologies; and (2) market demand -- influenced, for example, by the growth in demand for electricity and the future regulatory environment.

America's $6 billion clean coal commitment directly addresses the technological risk. By developing and demonstrating new technologies at commercial- or near-commercial scale, the risk of commercial deployment is reduced.

And it can give America a substantial marketing advantage in international trade by permitting the "packaging" of U.S. coal along with the technology to use it cleanly and efficiently.

America's clean coal commitment comes at a time when the nation's environmental consciousness -- and that of our global neighbors -- is on the rise. It also coincides with the national goal established by the President to assure American competitive preeminence into the 21st Century.

Perhaps most importantly, America's clean coal commitment represents a public and private sector partnership that can make coal an environmentally attractive fuel for the future, a fuel for energy security, and a fuel for continued economic growth.

1 The Nation has made a major investment in pollution control.

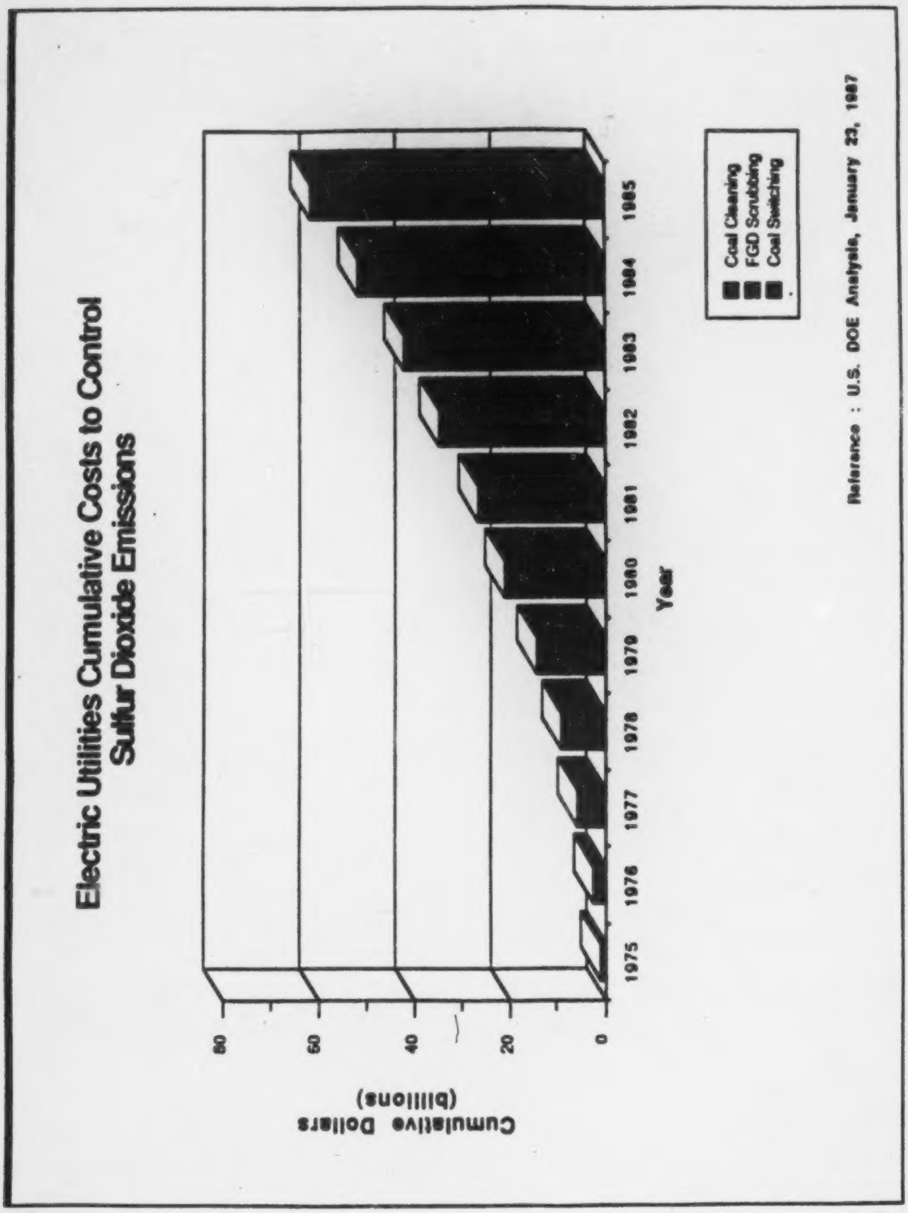
The U.S. investment in a cleaner environment began, in large measure, with the enactment in 1970 of the Clean Air Act. The Act, passed by Congress in response to the rise of environmental consciousness during the late 1960s, authorized the U.S. Environmental Protection Agency to establish limits on the release of sulfur dioxide, nitrogen oxides, particulate matter and other air pollutants from new facilities or from any existing plant undergoing major modifications. It also required States to regulate the release of air pollutants to protect human health and welfare.

Some electric utilities responded to the environmental mandate by switching their coal-burning facilities to low-sulfur coal to limit sulfur dioxide emissions. Others began purchasing pre-washed coal. Some companies chose to install flue gas scrubbers on new coal-fired power plants.

The Clean Air Act was modified in 1977 to impose, through New Source Performance Standards (NSPS), a further requirement that 70 to 90 percent of the original sulfur content in coal be removed before the combustion gases are released to the atmosphere. In effect this modification mandated that all utility coal-burning boilers built after September 18, 1978, be equipped with a scrubber. Scrubbing the flue gases released from a coal boiler was the only commercially available way (at that time) to reduce SO_2 emissions to meet the latest standards set under the Act.

Passage of the Clean Air Act and its subsequent amendments set America on a course that committed billions of dollars to environmental protection. From 1975 to 1986 U.S. electric utilities *alone* spent *$62 billion* to reduce emissions of sulfur dioxide from coal-fired power plants alone. An investment of even greater magnitude has also been made by industrial factories, manufacturing plants, and the automobile industry to control sulfur dioxide, nitrogen oxide, particulate matter and other air pollutants. In fact, in their May 1984 report, ***The Cost of Clean Air and Water - Report to Congress***, the Environmental Protection Agency estimated that between 1970 and 1984, U.S. industry spent more than $225 billion (in 1981 dollars) to control air emissions.

For older coal-burning facilities, the commercial options available during the last decade have been confined to coal cleaning, flue gas scrubbing, and coal switching. Figure 1 shows that the costs incurred (in current year dollars) for each approach amounted to $11 billion, $17 billion, and $34 billion, respectively, during the 1975 to 1985 period.



Electric Utilities Cumulative Costs to Control Sulfur Dioxide Emissions

Reference : U.S. DOE Analysis, January 23, 1987

Figure 1

These estimates were derived in the following manner:

Coal Cleaning -- The cost of coal cleaning is derived from Appendices B and C of an Energy Information Administration report (Reference 1) on coal production. Approximately two-thirds of Eastern coal -- coal produced east of the Mississippi River -- was cleaned in 1985, but the proportion was most likely less between 1985 and 1975. We conservatively assumed for this analysis that, during that period, 35% of the entire national coal production was cleaned. Various documents (for example, Reference 2) estimate that an average cost of cleaning is about $5 to $7 per ton. For this report, a conservative estimate of $5 per ton was assumed.

Approximately two-thirds of Eastern coal -- coal produced east of the Mississippi River -- was cleaned in 1985.

As an example of these calculations, in 1985 electric utilities consumed 690 million tons of coal. Of this amount, an estimated 35% or approximately 240 million tons, was cleaned. At $5 per ton for cleaning, the cost to utilities of coal washing totaled about $1.2 billion in 1985.

Similar calculations were performed for each of the years 1975 through 1984 using current year dollars. The cumulative costs of coal cleaning, through 1985, totaled $10.6 billion.

Flue Gas Scrubbing - The cost of flue gas scrubbing is derived from an estimate of scrubber capacity in operation during the 1975 to 1985 period. This estimate was derived from a summary report prepared by PEI Associates (Reference 3). Figure 2 depicts a bar chart showing scrubber capacity for each year.

To derive total costs, average costs of control (including capital, operating and maintenance costs) of 12 mils per kilowatt hour (Reference 3) and an average capacity factor of 0.6 are assumed. Costs were determined for each year using the formula:

Cost = 12 x 0.6 x Scrubber Capacity x 8760 Hours/Year
x Cost of Living Adjustment

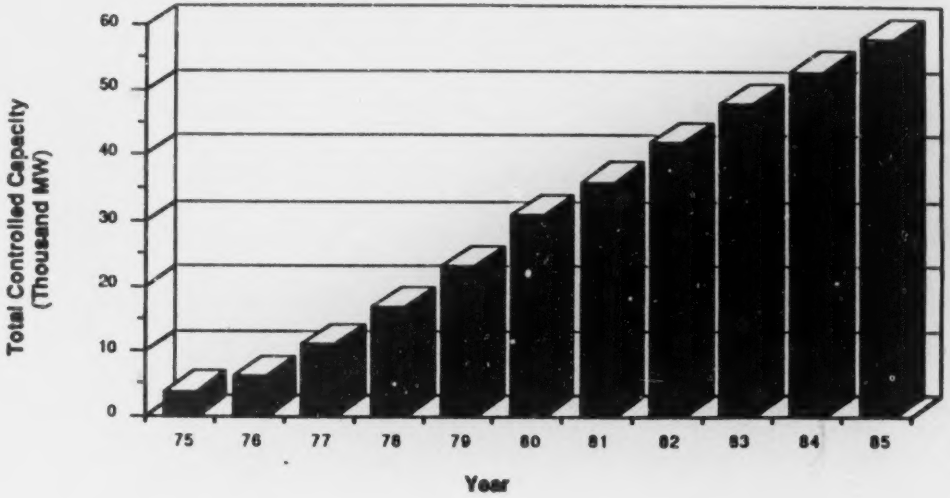
In fiscal year 1985, 58,000 megawatts of scrubber capacity was operational, leading to a cost of about $3.5 billion for that year. Proceeding in the same manner for 1975 through 1984, a cumulative cost of $17 billion during the period can be calculated.

Coal Switching -- To determine the cost of coal switching, the premium paid for low sulfur coal in 1985 was first estimated. This estimate was taken from an analysis described in Reference 4. The basic approach was as follows:

The estimate of the premium paid for low sulfur coal is based on actual costs of coal delivered to electric utility power plants in 1985. The analysis recognized that the cost of delivered coal versus sulfur content varies signi-

Operational Flue Gas Desulfurization Capacity

December 1975 - December 1985



Reference: PEI Report "History of Utility FGD Status Report", Prepared Annually, December 1975 - December 1985

Figure 2

ficantly across the geographic quadrants of the U.S. Therefore, calculations were based on data from each quadrant.

The calculation of the low sulfur premium begins by establishing a baseline cost (a surrogate for the cost of high sulfur coal), which is then subtracted from the actual cost. The baseline cost was determined judgementally for each quadrant. It involved examining the low, medium and high costs of about 80% of the observations (i.e., the highest 10% and the lowest 10% of the points were discarded), in the highest one-third of the data range, in terms of sulfur content. The baseline medians differed by region, but the highs and lows were consistently $0.15/million BTU (MMBTU) above and below the medians, as seen below:

Quadrant	High Sulfur Coal Cost (Cents/MMBTU) Low	Medium	High
NE	110	125	140
SE	115	130	145
NW	95	110	125
SW	110	125	140

By subtracting the baseline median cost from the actual cost paid for coal, the premium for each transaction (actually monthly averages were used for all the points in the figures) was calculated and the sum of all the differences represented the premium estimated for low sulfur coal.

Nationally, the result is estimated to be $5.3 billion for 1985. Reasonable upper and lower bounds are roughly $7.5 and $3.3 billion, respectively. This range is comparable to an EPA estimate being used to generate its 1985 Report to Congress, *The Cost of Clean Air and Water.*

For this report, $5.3 billion is taken to be the low sulfur premium for 1985. The low sulfur premiums for 1975 through 1984 were estimated as follows:

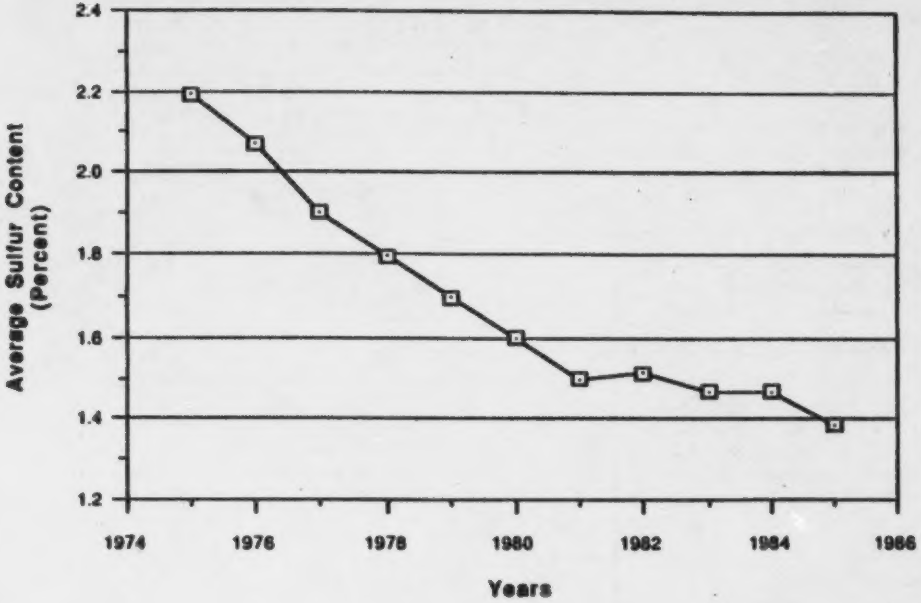
The average sulfur content of coal delivered to U.S. power plants decreased from about 2.2% in 1975 to about 1.4% in 1985. The data is found in Reference 5 and depicted in Figure 3. The annual premium for low sulfur coal is assumed to be the premium paid by the Nation for this decrease in sulfur content. The year 1975 is about the time when the sulfur content began to decrease. Therefore, to estimate cumulative costs, it is assumed that the 1975 low sulfur premium is zero and that the premium for each intervening year is:

The average sulfur content of coal delivered to U.S. power plants decreased from about 2.2% in 1975 to about 1.4% in 1985.

$$A \times \frac{S(1975) - S(year)}{S(1975) - S(1985)}$$

where A is the low sulfur coal premium for 1985 and S(year) is the average sulfur content of coal delivered to electric utilities for the year in question. The sum of the premiums for the years 1975 to 1985 leads to an estimated cumulative cost of $34 billion.

Average Sulfur Content of Coals Used by Electric Utlitities



Reference: Cost and Quality of Fuels for Electric Utility Plants
DOE/EIA-0191 (78) and (84)

Figure 3

2 The investment is paying off — sulfur emissions are down.

In terms of sulfur pollutants, the nation's air is cleaner today than at any time in the last decade. Sulfur dioxide emissions in 1984 -- approximately 24 million tons released over the entire year -- had been reduced by approximately 23% from their 1973 peak of 31 million tons. The 7 million ton reduction was accomplished even as annual coal use by U.S. utilities was *increasing*. From 1973 to 1985, while national sulfur emissions were on their way down, the use of coal by America's electric utilities was increasing by 78% -- from 389 million tons per year to 693 million tons per year.

Through switching from high to low sulfur fuels, using pre-cleaned coal, and installing flue gas scrubbing units, the nation's electric utilities have contributed significantly to the reduction in SO_2 emissions shown in Figure 4. Nationally SO_2 emissions from coal-fired electricity utilities have been reduced by 11.4%, from a high of 17.6 million tons in 1977 to an estimated 15.6 million tons in 1985.

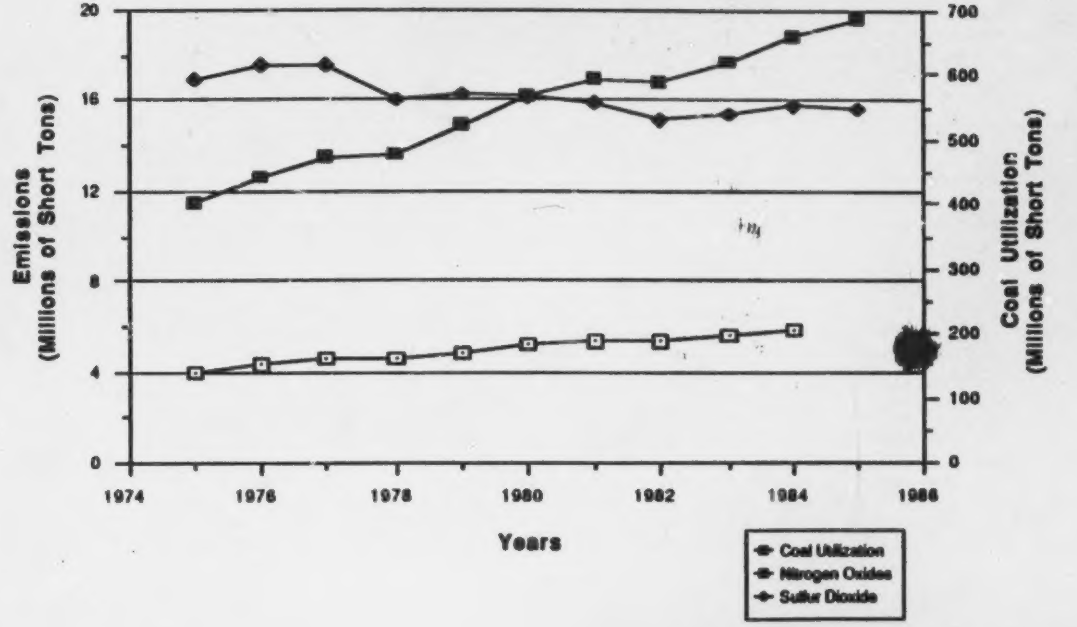
Utilities emissions of SO_2 in the northeast quadrant of the U.S. have dropped at an even faster rate than the nationwide trend. This is particularly important given the environmental sensitivity of much of this region and the adjacent regions of Canada. As shown in Figure 5, utility SO_2 emissions in the Northeast dropped by 19% from 1977 to 1985 compared to a national decline in utility emissions of 11.4%. During this period, utility coal consumption in the northeast quadrant grew by 13%.

The nationwide 11.4% reduction in SO_2 emissions by electric utilities since 1977 is significant but far from the true measure of environmental progress made overall since 1975. If the amount of SO_2 released per unit of coal burned in 1985 had been the same as in 1975, then considering the increase in coal use by utilities, 1985 emissions of SO_2 would have been 28.9 million tons rather than the actual emissions of 15.6 million tons.

The nationwide 11.4% reduction in SO_2 emissions by electric utilities since 1977 is significant but far from the true measure of environmental progress....

Trends in Emissions and Coal Consumption at Coal-Fired Power Plants in the United States

(Millions of Short Tons)



Note: 1985 data are preliminary estimates.

Reference: "Estimated Monthly Emissions of Sulfur Dioxide and Oxides of Nitrogen for the 48 Contiguous States, 1975-1984." ANL/ERS-TM-318; December 1986. (Dividing Metric Value by 0.9072)

Figure 4

Thus, by applying commercially available techniques, emissions in 1985 were 13.3 million tons less than they would have been at 1975 control levels. In other words, if electric utilities had not made the $62 billion investment in environmental control since 1975, theoretical 1985 emissions would be 185% of the actual 1985 emission level.

This 13.3 million ton SO_2 reduction is due to a combination of coal cleaning, coal switching and flue gas scrubbing. Coal cleaning and switching represented 8.9 million of the 13.3 million tons per year of SO_2 emission reductions in 1985. This estimate is derived from the reduction in average sulfur content delivered to electric utility power plants (Figure 3). That is, emissions would have been higher by the ratio by which average sulfur content of coal delivered to utility plants was reduced, i.e.:

Coal cleaning and switching represented 8.9 million of the 13.3 million tons per year of SO_2 emission reductions in 1985.

$$15.6 \times \frac{2.2}{1.4} - 15.6$$

where 15.6 (million tons per year) is the 1985 estimated electric utility SO_2 emissions, 2.2 (percent) is the 1975 average sulfur content of coals used by electric utilities, and 1.4 (percent) is the 1985 average sulfur content of coals used by electric utilities.

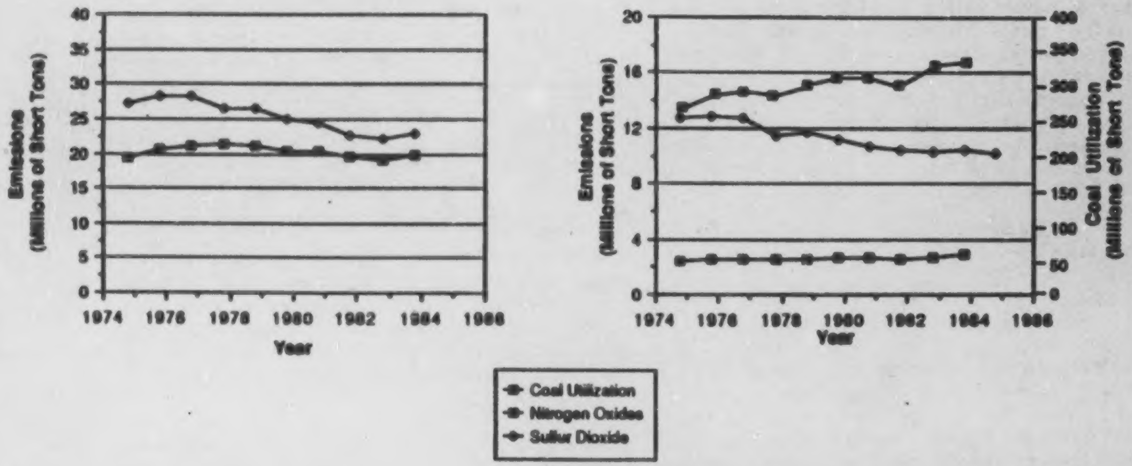
The remainder of the reduction is due to flue gas scrubbing. A detailed estimate for 1980 is presented in Reference 6, which estimated a reduction of SO_2 emissions by 1.7 million tons due to scrubbers. Adjusting this estimate for the increase in scrubber capacity from 31 megawatts to 58 megawatts between 1980 and 1985, and for the decrease in average sulfur content from 2.2% to 1.6% between 1975 and 1985 (Figure 3), it is estimated that SO_2 emissions were reduced by:

$$1.7 \times \frac{58}{31} \times \frac{2.2}{1.6} = 4.4 \text{ million tons}$$

due to scrubbers, in 1985, relative to what they would have been without scrubbers.

In this calculation, 1.7 (millions of tons per year) is the 1980 SO_2 emissions reductions due to scrubbers, 58 (thousand megawatts) is the 1985 operational scrubber capacity, 31 (thousand megawatts) is the 1980 operational scrubber capacity, 2.2 (percent) is the 1975 average sulfur content of coals used by electric utilities, and 1.6 (percent) is the 1980 average sulfur content of coals used by electric utilities.

Nationally, nitrogen oxide emissions (NO_x) have been held generally constant during the decade from 1975 to 1985 at approximately 20 million tons per year. In the Northeast quadrant, NO_x emissions have increased approximately 18% (from 2.9 to 3.4 million tons per year) during the same time period. Progress in reducing NO_x has lagged that for SO_2.



Trends in Sulfur Dioxide and Nitrogen Oxides Emissions in the United States (Millions of Short Tons)

Trends in Emissions and Coal Consumption at Coal-Fired Power Plants in the N.E. Quadrant (Millions of Short Tons)

Note: 1985 data are preliminary estimates

Reference: "Estimated Monthly Emissions of Sulfur Dioxide and Oxides of Nitrogen for the 48 Contiguous States, 1975-1984." ANL/ERS-TM-318; December 1985.
(Dividing Metric Value by 0.9072)

Figure 5

3 Further SO_2 reductions using conventional technology will be difficult.

To achieve additional SO_2 emission reductions using the techniques of the 1970s and early 1980s would pose severe problems due to the limitations of conventional controls. For example:

Coal Cleaning -- Conventional techniques for cleaning coal have a limited ability to remove sulfur. Sulfur occurs in coal principally in two forms (as shown graphically in Figure 6):

Pyritic sulfur is combined with iron and occurs as distinct, finely dispersed, often microscopic particles. In typical U.S. coals, pyritic sulfur can make up from 30% to 70% of the coal's total sulfur content.

Organic sulfur is bound chemically to the carbon atoms of coal. It, too, can comprise 30% to 70% of the total sulfur in coal.

Conventional coal cleaning removes only pyritic sulfur. Moreover, state-of-the-art physical cleaning technologies, which usually rely on specific gravity differences to separate impurities from coal, are capable of removing only 20 to 50% of the pyritic sulfur -- or approximately 10% to 30% of the total sulfur content. They are ineffective in removing any of the organic sulfur.

Flue Gas Scrubbing -- Flue gas scrubbing, applied to new power plants, can reduce SO_2 emissions by 90%. The U.S. electric utility industry operates more than 140 scrubbers and more than 70 additional units are under construction or planned.

Continued application of flue gas scrubbers could keep nationwide SO_2 emissions from rising but will not reduce overall emissions until existing, pre-New Source Performance Standards (the Clean Air Act-mandated emission levels for new plants) emitters are retired. A single scrubber for a typical new 500-megawatt coal burning plant may require an initial investment of $100 million or more, and capital costs for adding scrubbers on older plants can equal or exceed the original plant investment.

In addition, scrubbers consume 5% to 8% of the electrical output of a power plant, reducing the plant's overall efficiency and increasing the cost of electricity. Their byproduct, sludge, is difficult and costly to manage, and often scrubbers are unuseable because a utility does not have

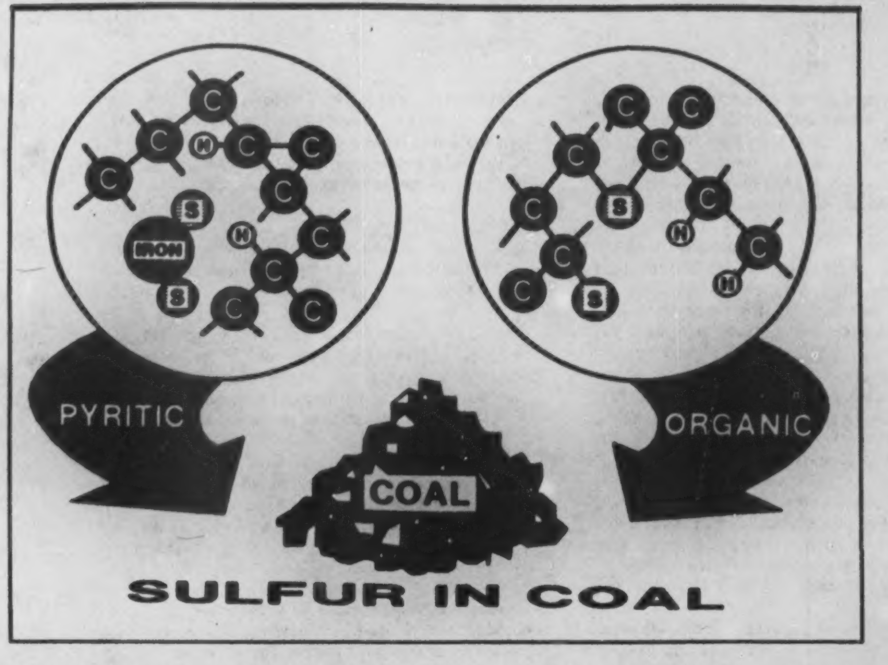


Figure 6

the land available for sludge disposal. (During its lifetime, for example, a typical 500-megawatt power plant with a scrubber is likely to require a sludge disposal pond more than 500 acres wide and more than 40 feet deep.) Today's flue gas scrubbers also cannot remove nitrogen oxides effectively.

Coal Switching -- Coal switching is extremely costly in terms of the premium paid to purchase and transport low sulfur coal. Because it is higher in cost than high sulfur coal, utility operating costs will be increased. Switching to low sulfur coal can also result in boiler derating (reducing power output) due to coal characteristics which do not meet or are in conflict with a particular boiler's design specifications.

Also, there is the incalculable cost of the social disruptions caused by shifting supply sources and displacing miners and their families.

4 The Nation's population of coal-fired plants is diverse and widely dispersed.

America's commitment to advanced clean coal technology is driven, in large measure, by the environmental, economic and performance-related benefits to be gained by an expanded menu of more flexible emission control options. The nation's utility population is widely dispersed and made up of units with widely varying designs, ages, sizes, etc. This heterogeneous nature of utility power generating equipment increases the complexity of using conventional pollution control options to achieve further reductions in emissions.

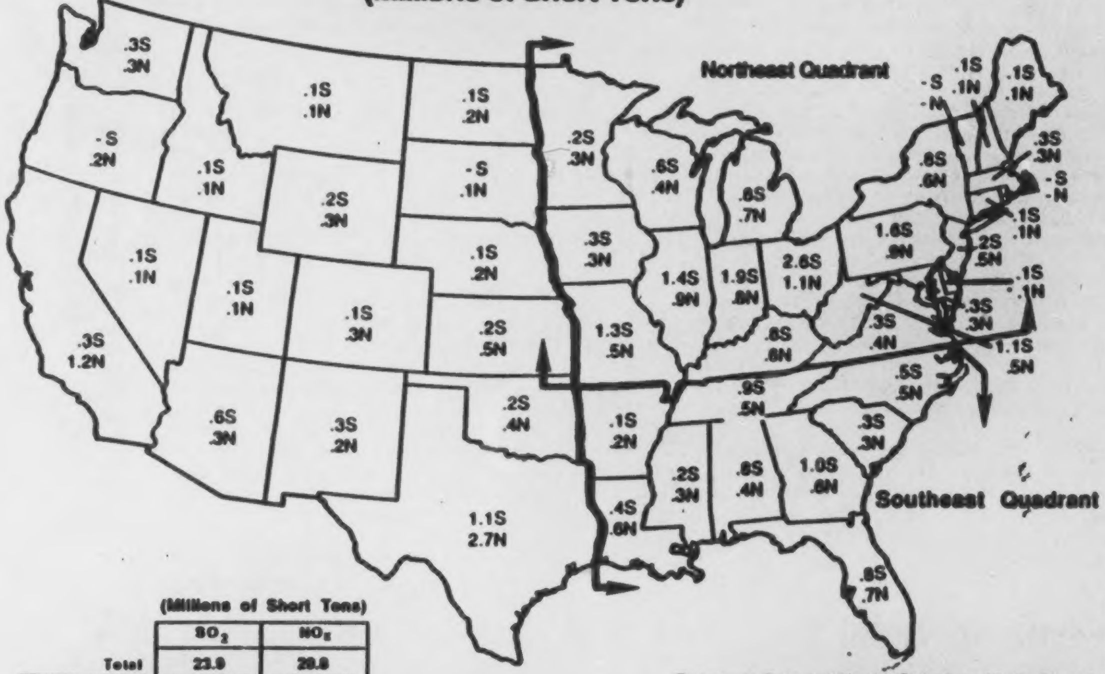
Sources of emissions -- Sulfur dioxide and nitrogen oxide emissions emanate from every state in the U.S. This is to be expected because sulfur dioxide is formed when any substance that contains sulfur is combusted. Likewise, any substance that contains nitrogen or is in the presence of nitrogen (in air, for example) forms nitrogen oxides when it is burned at sufficiently high temperatures.

As can be seen in Figure 7, the majority of SO_2 released to the atmosphere from the continental U.S. comes from the eastern U.S. (i.e., the states that border or are east of the Mississippi River). In fact, based upon 1984 emissions data, almost 20 million tons, or 83% of the SO_2 from U.S. sources, came from the eastern states, with 75% from the northeastern states (called the "northeast quadrant" in this report).

Nitrogen oxide releases, on the other hand, are spread fairly evenly throughout the U.S. relative to population density. The eastern states, with the highest population density, emitted 13.6 million tons or 65% of the NO_x released in the continental U.S. in 1984, with 70 percent of the eastern emissions from the Northeast quadrant.

Of the 23.9 million tons of SO_2 released from U.S. sources in 1984, approximately 18.9 million tons, or 80 percent, emanated from stationary sources combusting fuels. As shown in Figure 8 and discussed in Reference 7, these stationary sources include electric utilities, industrial, commercial/institutional and residential boilers. Industrial processes (e.g., iron and steel mills, smelters, etc.) emitted 3.4 million tons, or 14 percent of the total in 1984. Transportation sources, including highway vehicles and aircraft, railroad vehicles, maritime vessels and other off-highway vehicles, and all other sources released 1.6 million tons of SO_2 or 6.8 percent of the total, in 1984.

Emissions of SO_2 and NO_x in Continental U.S. (1984)
(Millions of Short Tons)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.1S
.1N
.3S
.3N
1.1S
.5N
Northeast Quadrant
Southeast Quadrant

(Millions of Short Tons)

	SO_2		NO_x	
Total	23.9		20.8	
N.E. Quadrant	14.9	62.3%	9.5	45.5%
S.E. Quadrant	4.9	20.5%	4.1	19.6%

S = Sulfur dioxide
N = Nitrogen oxides

Reference: "Estimated Monthly Emissions of Sulfur Dioxide and Oxides of Nitrogen for the 48 Contiguous States, 1975-1984." ANL/EES-TM-318; December 1986. (Dividing Metric Value by 0.9072)

Figure 7

Among the stationary fuel combustion sources, electric utilities released 16.5 million tons of SO_2, or nearly 69% of the total U.S. emissions in 1984. As the earlier sections of this report describe, this is down considerably from the emission levels of the mid-1970s.

Approximately 96 percent of the total utility SO_2 emissions -- 15.8 million tons out of 16.5 million tons -- came from coal-fired power plants. The remaining 0.7 million tons came from oil- and natural gas-fired facilities.

Industrial sources accounted for the majority of the remaining SO_2 released from stationary fuel combustion sources, emitting 2.4 million tons of SO_2, or 10%, in 1984. This, too, is down from over 3 million tons released by industrial combustion sources in the mid-1970s.

Of the 20.9 million tons of NO_x released to the atmosphere in the U.S. in 1984, transportation sources, primarily highway vehicles, accounted for about 7.5 million tons, or 37%. Stationary source fuel combustors, primarily electric utilities and industrial sources, released about 10 million tons, or 49%. All other sources (e.g. industrial processes and the open burning of solid waste, in addition to forest fires) accounted for the remaining 3.4 million short tons of NO_x released in 1984. Nationally, NO_x emissions in 1984 were at about the same level as in 1975.

The distribution of emission sources in the Northeast quadrant reveals the affect of the concentration of coal-fired power plants in this region. Utilities contribute 77% of SO_2 in this region and 48% of the national SO_2 emission levels. The NO_x emissions level distribution for this region reflects the national pattern.

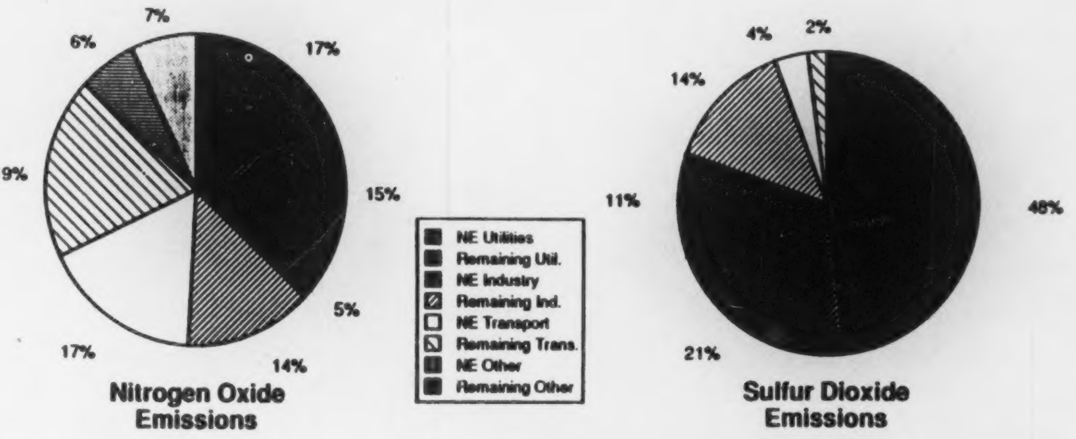
Characteristics of Emitters -- Since eastern coal-fired power plants are the primary source of the SO_2, and to a lesser extent the NO_x emissions inventory in the U.S., information on the characteristics of these power plants is important in determining the effectiveness of innovative clean coal technologies in reducing emissions.

Eastern U.S. coal-fired power plants have very diverse characteristics. They have been constructed in a wide variety of sizes and configurations. Their age varies significantly. They differ widely in terms of space availability, site characteristics and coal type used. For example:

Coal Heat and Ash Content

Coals used by these plants vary in heat content and ash content. Both factors are very important in the operation of boilers and solids handling equipment.

For example, the majority of boilers operating in the U.S. incorporate a *dry bottom* design -- that is, the ash (the noncombustible inorganic mineral matter) collects in the bottom of the boiler in dry form. To operate properly these boilers require a coal with a *high ash fusion temperature*, meaning the ash does not melt easily during the combustion process. On the other hand, Percentage of National vs Northeast Quadrant Emissions of SO_2 and NO_x in 1984



Reference: "Estimated Monthly Emissions of Sulfur Dioxide and Oxides of Nitrogen for the 48 Contiguous States, 1975-1984", ANL/EES-TM-318; December, 1986. (Dividing Metric Values by 0.9072)

Figure 8

some utility boilers -- about 15-20 percent of the eastern utility boiler population -- incorporate a *wet bottom* design. That is, when the coal is burned, the resulting ash is hot enough to melt and run to the bottom of the boiler. Therefore, these boilers require coals with a low-ash fusion temperature, or in other words, a coal whose ash liquifies at relatively low temperatures.

Utilities, therefore, must ensure that the coal feed matches the characteristics of the boiler.

Coal Grindability

Coal pulverizers -- the devices power plants use to crush coal to a size where it will form a combustible cloud inside the boiler -- are also designed for specific types of coal. If an alternative coal is more difficult to grind, or contains too much ash, then the pulverizer cannot provide adequate fuel to the boiler.

Coal Sulfur Content

Sulfur content also varies from below one percent to more than three percent among coals used by the power industry. Although the sulfur content of coal does not significantly affect combustion performance, it does affect the performance of electrostatic precipitators. Electrostatic precipitators are devices designed to collect dust particles carried out of the coal boiler by the combustion gases. For coals below one percent sulfur, performance of an electrostatic precipitator designed for high sulfur coals, becomes less effective.

Figure 9 shows the percentage of sulfur in coal used by eastern power plants in 1984. Only a fraction of northeastern plants use "high sulfur" coal, i.e., coal exceeding three percent sulfur. More than half of the northeastern power plant capacity is fueled with coal that has a two percent sulfur content or less.

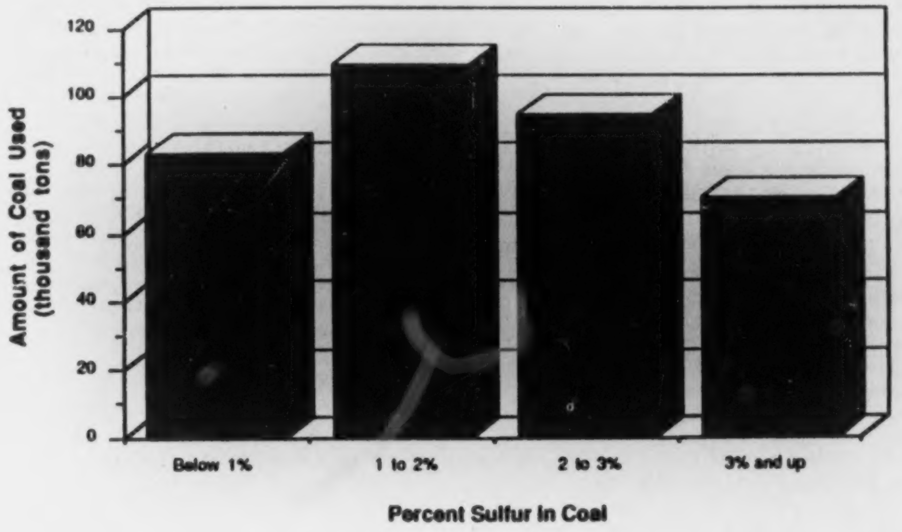
The significance of this fuel use pattern is that current SO_2 control technologies are particularly unfavorable from a cost-effectiveness perspective when used on units firing low- or medium-sulfur coal. A major challenge that can be answered by innovative clean coal technology is the development of control systems that are substantially less expensive and more broadly applicable to the full range of coals used by today's power plants.

Power Plant Age

Figure 10 shows the capacity (in megawatts) of the eastern coal-fired power plants in the U.S. that are exceeding the 1.2 pounds per million BTU emission rate set for new facilities by the Environmental Protection Agency's New Source Performance Standards. This capacity is shown by unit age and size. As the graphs depict, 70% of the power plants were built between 1961 and 1980 (5 to 25 years old) with a little more than half of those built between 1971 and 1980 (5 to 15 years old). Nearly one quarter were built between 1951 and 1960 (25 to 35 years old).

The aging character of many of the nation's coal-fired boilers means that many utilities will soon be required -- if they are not already -- to

Coal Quality in 1984 for Power Plants in U.S. Northeast Quadrant



Reference: 1984 Data Retrieved from FERC Form 423, Coal Sales to Powerplants

Figure 9

make decisions about the future of these facilities. Since coal-fired boilers were originally designed to operate for approximately 30 years, plant operators will be faced with the need to refurbish existing facilities or alternatively, to shut them down. Since taking a plant out of service is an expensive alternative, many utilities will likely attempt to extend the lifetime of older facilities.

Thus, a window is beginning to open for new technologies to be considered in utility modernization plans. As subsequent sections of this report describe, new clean coal concepts offer the potential not only for extending a plant's useful life but doing so in a manner that greatly reduces the refurbished plant's emissions without adding excessively to the cost of electricity. It is important that these technologies be developed and demonstrated by the early to mid 1990s, the timeframe in which the modernization "window" will be fully opened.

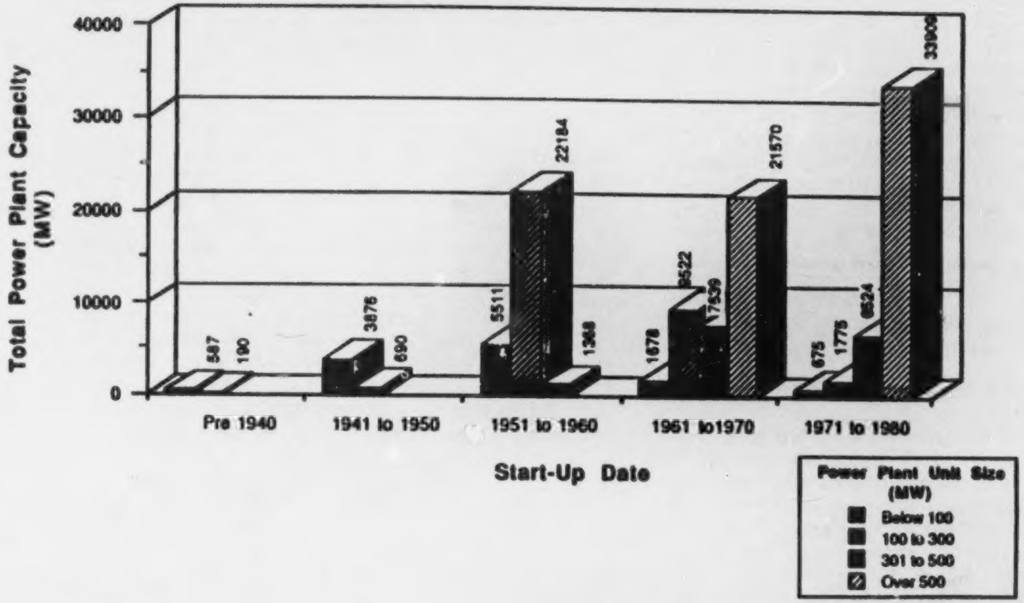
Boiler Size

More than 90% of the eastern coal-fired generating capacity is comprised of boilers which are greater than 100 megawatts in size. Nearly one-third (32%) of the capacity is comprised of units between 100 and 300 megawatts, 14% are between 300 and 500 megawatts, and 44% are 500 megawatts or larger. Thus, for a control technology to be effective for the majority of power plant capacity, it must be capable of cost-effectively controlling emissions from all unit sizes ranging from below 100 to more than 500 megawatts.

In summary, emission reductions have come from the use of commercially available options: coal cleaning, flue gas scrubbing and coal switching. Further significant reductions using these approaches can be obtained only at great cost and dislocation. Moreover, the wide range of diversity in the nation's coal boiler population imposes further limitations on conventional controls.

...the wide range of diversity in the nation's boiler population imposes further limitations on conventional controls.

Innovative clean coal technologies, however, offer the potential for further significant reductions in a cost-effective manner from existing as well as new sources (Figure 11). As the next section of this report will describe, many of the new clean coal technologies control NO_x as well as SO_2. They produce either saleable or more easily disposed of wastes. They offer greater fuel flexibility compared to conventional technology, which allows continued use of higher sulfur coals and obviates the need for major dislocations in the workforce. These new technologies are also capable of maintaining acceptable economic performance over a wide range of boiler sizes and types, and used in combination with a general plant refurbishing, they can often extend a power plant's useful life by another 25 to 30 years.



Coal Capacity Emitting Over 1.2 Pounds
Sulfur Dioxide per Million Btu Input in the Eastern United States
Capacity (MW) by Age and Size

Reference: 1980 data retrieved from "Electric Utility Unit Inventory" E.H. Pechan & Associates, December 1982.

Figure 10

Options for Further Reduction of SO_2 and NO_X

Install SO_2 Scrubbers	Switch to Low Sulfur Coal	Conventional Coal Cleaning	Innovative Clean Coal Technologies
Advantage:	**Advantage:**	**Advantages:**	**Advantages:**
• Proven method to significantly control SO_2 • Allows existing coal to be used	• Proven method to significantly control SO_2	• Allows existing coals be used • Improves boiler performance	•Much more cost effective in control of SO_2 • May control NO_x as well • Some could be used to reduce emissions, increase plant output, extend plant life – all in one! • Produce usable or easily disposable waste
Disadvantages:	**Disadvantages:**	**Disadvantage:**	**Disadvantage:**
• Very expensive • Reduces Plant efficiency • Produces large quantities of difficult-to-handle sludge	• Would displace many miners of high-sulfur coals • High cost - would result in boiler deratings - premium on low-sulfur coals - would require upgrading of particulate controls	• Can remove only 10-30 percent of the sulfur from most coals	• Full slate of technologies not yet commercially available

Figure 11

5

Significant opportunities exist for new clean coal technologies because of past expenditures and a national commitment to future support.

Innovative clean coal technologies offer significant advantages over conventional SO_2 and NO_x control options.

Most conventional pre-NSPS coal-fired power plants in the U.S. (see section 1) are equipped with only particulate removal devices. Sulfur emissions are directly linked to the sulfur content of their coal feed. A typical power plant in this category is about 35 to 38% efficient in producing electricity from raw coal feed.

A coal-fired plant built since 1978 is typically less efficient, due to the need to install flue gas scrubbers which use 5 to 10% of the plant's electricity. The capital cost for a new plant in the 350-1000 megawatt size range is about $1500-$1800 per kilowatt, roughly 20% of which is associated with required environmental controls including a flue gas scrubber. With routine maintenance, a coal-fired power plant is expected to perform at design specifications for about 30 years. Conventional power plants are generally very sensitive to coal feed (as was described in the previous section) due to varying boiler types and coal and ash handling equipment.

No single technology, even the more fuel-flexible advanced concepts, will likely meet the needs of all utilities. Plant size and age, boiler type, coal feed, geographical requirements, and even public utility commission policies and rules will have a large bearing on the choice of technology.

Consequently, a broad slate of technologies must be developed. Ideally, these new technological options would be relatively insensitive to coal characteristics, but would maintain a consistently high degree of environmental effectiveness, economic viability and plant reliability.

New clean coal technologies now emerging from a decade of smaller-scale development have many, if not all, of these attributes. Several are described below, and more detailed descriptions can be found in Appendix A.

In general, for purposes of this report, the emerging clean coal technologies can be grouped into two major categories: (1) *Retrofit* technologies and (2) *Repowering* technologies.

Retrofit technologies would be used on existing plants primarily to reduce emissions. Repowering technologies would replace a portion of the original plant, perhaps as part of a general plant refurbishing, and may increase capacity while reducing emissions.

Several of the emerging technologies, particularly those used for repowering, could also be candidates for new, so-called "grassroots" power stations.

The advantages of these innovative technologies can be grouped as follows:

Environmental Performance (Figure 12)

At the "front end" of the coal fuel chain, conventional coal cleaning modifies the mined coal to meet the customers' needs in terms of size, moisture, mineral concentration and heat content. (In some cases, particularly in the West, the coal is only crushed.) As described earlier, conventional coal cleaning is limited to removal of a portion of the pyritic sulfur and ash. It results in only a 10 to 30 percent reduction in SO_2 emissions, depending upon the parent coal, and does not control NO_x emissions at all.

At the "back end" of the fuel chain, conventional flue gas scrubbing technologies are designed to remove 90 percent of the SO_2 in a power plant's flue gas. In a typical *wet scrubber*, SO_2-laden gases from the boiler are sprayed with an aqueous mixture of lime or limestone. The SO_2 combines with the lime/limestone and is "scrubbed" from the gases. The gases are then reheated (to provide bouyancy) and routed to the smokestack. Newer, *dry* scrubbers, used predominately for low-sulfur coals in the West, spray smaller droplets of lime dissolved in water into the combustion gases in such a manner to rapidly evaporate the moisture. By themselves, flue gas scrubbers do *not* control NO_x emissions. The wet scrubber types produce a considerable amount of a pasty, difficult to handle sludge -- about one acre-foot per megawatt per year.

Several innovative *retrofit* clean coal technologies offer improved environmental performance over these conventional technologies. In the coal cleaning area, for example, new advances are being made in:

Advanced physical coal cleaning -- techniques involving a variety of approaches such as fine grinding, "true heavy liquid" cyclones, froth flotation, and selective coalescence.

Chemical coal cleaning -- concepts that expose coal, for example, to molten chemicals such as sodium hydroxide which break the chemical bonds of the organic sulfur.

Microbial coal cleaning -- relatively new techniques that employ microbes to degrade sulfur in coal into a removeable form.

Advanced physical coal cleaning technologies can potentially reduce SO_2 emissions by 65 percent, and advanced chemical and microbial processes are believed capable of achieving 90 percent or better SO_2 emission reductions, depending on the organic content of the original coal. Utilization of coal slurries prepared from coal

Environmental Performance of Innovative Clean Coal Technologies in Comparison to Conventional Coal-Fired Power Plant

Technology	% SO_2 Reduction	NOx Emitted	Waste Characteristics
CONVENTIONAL			
Coal Cleaning	10-30	No change	Solids disposal
Flue Gas Scrubber	90+	No change	Sludge
RETROFIT			
Advanced Flue Gas Cleanup	90+	High reduction	None, Byproduct produced
Limestone Injection Multistage Burner	50-60	Moderate reduction	Dry nontoxic powder suitable for landfill
Slagging Combustor	50-90	Moderate reduction	Dry non-toxic powder suitable for landfill
Gas Reburning	10-20	Moderate reduction	None produced
In-duct Sorbent Injection	50-70	No change	Dry powder suitable for landfill
Advanced Coal Cleaning	30-90	No change	Solids disposal
Coal Slurry	10-90	No change	Solids disposal
REPOWERING			
Integrated Gasification Combined Cycle	95-99	Moderate reduction	Usable slag, saleable sulfur and small quantities of other solid wastes
Pressurized Fluidized Bed Combustion	90-95	Moderate reduction	Dry granular nontoxic solid waste
Atmospheric Fluidized Bed Combustion	85-90	Moderate reduction	Dry granular nontoxic solid waste

Figure 12

processed by these advanced coal cleaning technologies results in the same emission reductions as the dry cleaned coal.

Several retrofit technologies have also emerged within the last few years that can be integrated at the power plant. These include:

Limestone Injection Multi-Stage Burners -- a technology that injects sulfur-absorbing limestone into the fuel-rich "reducing" zone of a pulverized coal burner.

Slagging combustors -- devices that can control or remove objectionable sulfur and particulate matter from a coal-derived fuel before it is injected into retrofitted oil or gas boilers or heaters.

Gas Reburning -- a concept that injects a secondary fuel, such as natural gas, above the primary combustion zone to create a fuel-rich region in which nitrogen oxides are converted to harmless products.

In-Duct Sorbent Injection -- a technique that injects sulfur-capturing sorbents directly into a power plant's ductwork leading from the boiler to the stack.

Advanced Flue Gas Cleanup -- a variety of innovative scrubber technologies that use chemicals such as copper oxide or electron beam irradiation to improve the effectiveness of pollutant capture.

These devices, either separately or in combination, not only control SO_2 but NO_x as well. In addition, they produce dry wastes which can be disposed of easily and in an environmentally safe manner. Although the SO_2 reduction potential of some of these technologies is lower than conventional flue gas scrubbing, the levels will likely be sufficient to meet possible future requirements for emission reductions at existing plants.

Many *repowering* technologies also have excellent emission reduction potential. Examples are:

Integrated Gasification Combined Cycle -- a power generating configuration in which coal is first converted to a combustible gas, cleaned and then used to power a gas turbine and steam turbine combination.

Fluidized Bed Combustion -- a technology in which coal is injected into a hot "bed" of sulfur-absorbing limestone or dolomite suspended inside the combustor by upward-blowing jets of air (as shown in Figure 13).

The integrated gasification combined cycle (IGCC) is an environmentally superior technology. The Cool Water IGCC Demonstration Plant in Daggett, California -- the nation's first commercial-scale demonstration of this new technology -- has shown the capability to reduce SO_2 emissions by more than 99 percent. NO_x emissions have also been reduced by 40 percent compared to a conventional coal-fired plant. The waste streams consist of a saleable sulfur, slag that can be used in road beds, concrete or asphalt, and small quantities of other solid wastes.

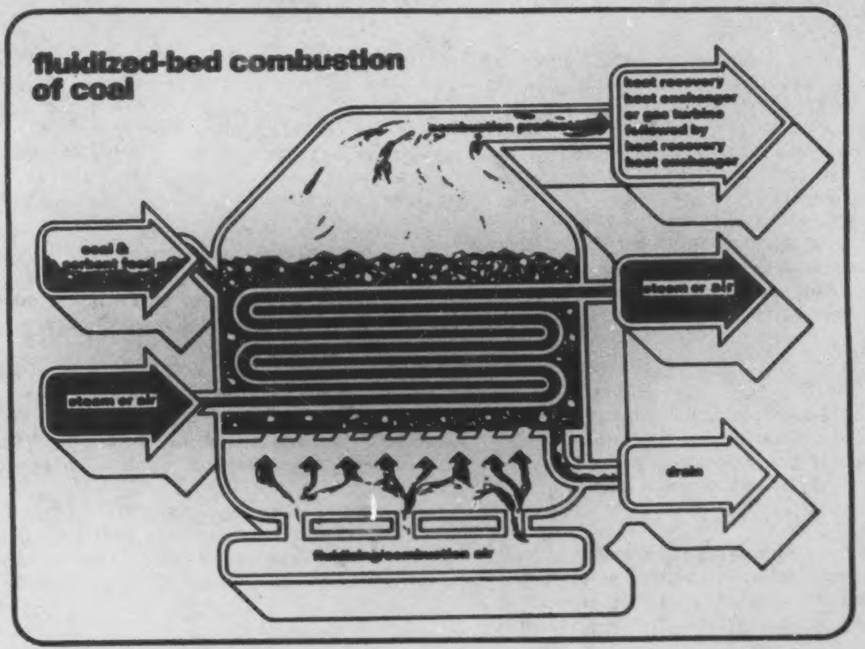

fluidized-bed combustion of coal
heat recovery heat exchanger or gas turbine followed by heat recovery heat exchanger
combustion products
coal & sorbent feed
steam or air
steam or air
drain
fluidizing/combustion air

Figure 13

The atmospheric pressure fluidized bed combustor, based on thousands of hours of operation at the large industrial boiler scale, is capable of achieving 90 percent SO_2 emission reduction *inside the boiler*, thereby requiring that no scrubber be installed. Also, because of the fluidized bed combustor's inherently low operating temperature -- 1450-1700 degrees F compared to the 2700+ degrees of a conventional coal burner -- NO_x emissions of 0.2 to 0.5 pounds per MMBTU can be achieved compared to the existing utility NSPS standards of 0.6 pounds per MMBTU.

The pressurized fluidized bed combustion technology -- in which the combustor's internal pressure is boosted to 6 to 16 times atmospheric pressure -- has demonstrated the capability to reliably reduce SO_2 emissions by 95 percent and lower NO_x emissions to 0.2 to 0.5 pounds per MMBTU.

The solid waste stream for fluidized bed combustors is an easy-to-handle material consisting of a granular, chemically inert coal ash and spent sorbent (calcium sulfate) which can be easily disposed of for landfill purposes or used for industrial or agricultural applications.

Technology Availability (Figure 14)

Flue gas scrubbing technologies (e.g., lime/limestone scrubbers) and conventional coal cleaning technologies (e.g., heavy media cyclone) are commercially available. Chemical and microbial coal cleaning are being evaluated on a pilot scale with commercialization anticipated in the late 1990s.

One version of the limestone injection multistage burner is currently being demonstrated by the Environmental Protection Agency, and a second demonstration is planned. Demonstrations of various combustion modification processes (including limestone injection multistage burners, slagging combustors, gas reburning and sorbent injection) are also part of DOE's Clean Coal Technology Demonstration program and are expected to be commercially deployed in the early 1990s.

Advanced flue gas cleanup technologies, such as the copper oxide and electron beam processes, are being developed at the pilot scale by DOE and several industrial partners. Advanced physical coal cleaning processes, such as the "reverse column flotation process" partially funded by the Pennsylvania Energy Development Administration, are being demonstrated. Development of combustion techniques for coal slurries has proceeded through the pilot stage with no technical barriers.

Considerable demonstration activities have focused on the repowering technologies, i.e. integrated gasification combined cycle, pressurized fluidized bed combustion and atmospheric fluidized bed combustion. The atmospheric fluidized bed concept is commercially competitive in large industrial applications (200,000 pounds per hour of steam or greater) and units are available in sizes up to 500,000 pounds of steam per hour. Eighteen U.S. boilermakers now offer commercial units and 105 atmospheric fluidized bed boilers are either operational or committed to construction. Additionally, the utility industry is proceeding with three large atmospheric fluidized bed utility demonstration plants:

o Colorado-Ute, Nucla Station, 110 megawatts - a new circulating-bed fluidized bed boiler built to repower 36 megawatts of existing stoker-fired steam generator capacity and power a new 75 megawatt steam turbine. The boiler is expected to begin service in 1987.

o Northern States Power, Black Dog Station, 125 megawatts -- a repowering of an existing 100 megawatt pulverized coal boiler that is being upgraded to 125 megawatts with a bubbling-bed

Availability of Innovative Clean Coal Technologies

Technology	Expected Availability	Status
RETROFIT:		
Advanced Flue Gas Cleanup	1995-2000	Pilot
Limestone Injection Multistage Burner	1990-1995	Demonstration
Slagging Combustor	1990-1995	Demonstration
Gas Reburning	1990-1995	Demonstration
In-duct Sorbent Injection	1990-1995	Demonstration
Chemical and Microbiological Coal Cleaning	1995-2000	Pilot
Physical Coal Cleaning	1990-1995	Demonstration
Coal Slurry	1990-1995	Demonstration
REPOWERING:		
Integrated Gasification Combined Cycle	1990-1995	Demonstration
Pressurized Fluidized Bed Combustion	1990-1995	Demonstration
Atmospheric Fluidized Bed Combustion	1990-1995	Demonstration

Figure 14

fluidized bed boiler. Operation began in 1986.

- **Tennessee Valley Authority**, Shawnee Station, 160 megawatts -- a new atmospheric fluidized bed boiler to repower and extend the life of an existing 160 megawatt steam turbine generator through installation of a bubbling-bed fluidized bed boiler. Startup is expected in 1988.

Integrated gasification combined cycle (IGCC) and pressurized fluidized bed combustion (PFBC) will likely be commercialized in the early 1990s. The DOE Clean Coal Technology Program currently includes two IGCC demonstration projects (incorporating advanced subsystems such as hot gas clean-up), and several U.S. utilities have announced plans to install IGCC systems.

The American Electric Power Service Corporation, also a part of the DOE Clean Coal Technology Program, has been selected to construct and operate a 70 megawatt pressurized fluidized bed combustion combined cycle demonstration plant in Brilliant, Ohio.

Technical and Economic Performance (Figure 15)

Retrofit technologies generally cause some losses of efficiency (3 to 10 percent) and power output because energy is required to operate them. Post-combustion cleanup technologies, namely conventional and advanced flue gas scrubbing, have similar economic performance penalties. Flue gas scrubbing generally costs more than combustion modification processes such as limestone injection multistage burner, slagging combustors, gas reburning and sorbent injections. Pre-combustion cleanup, i.e., coal cleaning and coal slurry preparation, can result in slight efficiency increases due to less ash handling, however fuel costs are increased. In general, the advanced retrofit control devices expand the range of coal types that can be cost-effectively controlled and are not as space or site limited as flue gas scrubbing.

Repowering technologies often increase efficiency and boost power output. To repower an existing coal-fired power plant, the existing boiler would be replaced with a new coal gasifier or pressurized fluidized bed combustor along with a gas turbine, gas cleanup system and heat recovery boiler. The remaining equipment (coal handling, steam turbine and power generation equipment) would likely be refurbished. Although repowering requires significant capital investments, the increased power output offsets most of the capital cost.

For example, repowering an existing coal-fired power plant with IGCC -- a gasifier-turbine configuration -- would require an investment of $1100 to $1300 per kilowatt. The cost of electricity, however, would only increase by 1-2 mills per kilowatt hour because the refurbished plant would be capable of generating more electric power than the original plant. And for that investment, SO_2 emissions from the repowered portion of the plant would be reduced by up to 99% and NO_x emissions substantially lowered.

Repowering with IGCC can increase the efficiency of a power plant from a nominal 35% to more than 40% and boost its power output by 50% to as much as 150%.

Repowering using pressurized fluidized bed combustion technology increases plant efficiency from a nominal 35% to approximately 38% and increases power output by up to 50%. Capital costs are somewhat less ($800-$1000 per kilowatt), but because the boost in power output is less than IGCC, the cost of electricity is somewhat greater -- about 4-6 mills per kilowatt hour.

Atmospheric fluidized bed combustion repowering would not change the power plant's efficiency measureably, although it would result in a 10 to 15 percent increase in power output. The initial investment cost is lower ($700 to $900 per kilowatt) but the relatively small increase in power output results in a 6-8 mill per kilowatt hour increase in the cost of electricity.

Technical And Economic Performance of Innovative Clean Coal Technologies in Comparison to Conventional Coal-Fired Power Plant

Technology	Efficiency	Power Output	Plant Life	Incremental Cost of Electricity* (mills/KWH)	Capital Cost ($/KW)
CONVENTIONAL					
Coal Cleaning	Small increase	No change	Slight extension	2-3	Additional fuel cost only
Flue Gas Scrubber	Decrease	Moderate decrease	No change	9-11	100-200
RETROFIT					
Advanced Flue Gas Cleanup	Decrease	Small decrease	No change	10-12	175-190
Limestone Injection Multistage Burner	Decrease	Small decrease	No change	5-8	80-110
Slagging Combustor	Small decrease	Small decrease	Slight extension	1-2	50-60
Gas Reburning	No change	No change	Slight extension	Depends on gas price	10-20
In-duct Sorbent Injection	Small decrease	Small decrease	No change	2-4	40-90
Advanced Coal Cleaning	Small increase	No change	Slight extension	6-21	Additional fuel cost only
Coal Slurry	Small decrease	Small decrease	No change	11-23	20-60
REPOWERING					
Integrated Gasification Combined Cycle	Moderate increase	50-150% increase	Moderate extension	1-2	1100-1300
Pressurized Fluidized Bed Combustion	Slight increase	40-50% increase	Moderate extension	4-6	800-1000
Atmospheric Fluidized Bed Combustion	No change	10-15% increase	Moderate extension	6-8	700-900

* Assumes base is conventional coal-fired power plant with only particulate removal devices. For repowering technologies, capital costs are relatively high because the output, i.e. capacity of the plant is increased. The incremental cost of electricty are those costs associated with reducing emissions from the original plant.

Figure 15

6 The Nation has built a solid research & development foundation for clean coal technologies.

America's commitment to clean coal technologies began in hundreds of publicly and privately financed research laboratories and test sites in the 1960s and 70s.

Fluidized bed technology, for example, originated as an adaptation of a concept used initially for breaking down the dense components of crude oil. A small 500-kilowatt atmospheric unit built in 1965 at Alexandria, Virginia, served as one of the earliest test beds for this innovative coal combustion concept. By 1980, the first industrial scale unit was in operation. Today, thousands of hours of operating data have been accumulated in a variety of industrial units across the country. And with the start-up last year of Northern States Power Company's atmospheric fluidized bed retrofit boiler, the technology is now moving into utility-scale operation.

The limestone injection multistage burner technology originated in the late 1960s and early 1970s with small scale tests conducted by the Environmental Protection Agency and its predecessors. Today, the technique is being demonstrated on a 105-megawatt utility scale boiler. The copper oxide advanced flue gas cleanup process was developed and refined through five years of research at the government's Pittsburgh Energy Technology Center before it was deemed ready for utility "slipstream" tests. Advanced slag-rejecting combustors were a spin-off of research in the late 1970s and early 1980s to develop ultra-high temperature coal combustors for the magnetohydrodynamics power generating concept.

Many of these emerging clean coal technologies originated in the aftermath of the 1973 OPEC oil embargo. With the nation's economy shaken by the sharp rise in oil prices and with increased concern over the vulnerability of imports, the U.S. coal research program in the 1970s was driven principally by a goal of displacing liquid and gaseous fossil fuels.

In 1980, the perception of primary R&D needs changed. With increased attention focused on the issue of "acid rain" and the compatibility of coal with America's environmental goals, the national research program began to concentrate more on the development of technologies to control SO_2 and NO_x either before, during or after coal combustion.

Many of the technologies, under development in the 1970s for other purposes, also had the potential to be attractive alternatives to the commercially available pollution control technologies.

From 1980 to 1985, the U.S. spent approximately $3.2 billion on the development of new coal technology, as shown in Figure 15. Of this, approximately $1.6 billion was to develop innovative clean coal technology. This funding includes both Government and private sources.

The technical groundwork developed in the late 1970s and early 1980s has been critical in gauging the readiness of emerging clean coal technologies for scale up and eventual commercialization. Based on what was learned within the last six years particularly, the nation now has the data to make much better projections of the reliability, costs and environmental performance of the new clean coal technologies now moving into the commercial demonstration phase.

The progress made, in fact, provides the technological basis for proceeding with the federal Clean Coal Technology Demonstration program that began in 1986.

Coal Technology R&D Funding

TECHNOLOGY	1981-1985 R&D FUNDS ($ in millions) TOTAL	DOE/FE	EPRI	EPA	TVA	GRI	ASSOC.	STATES	PRIVATE COFUNDING
Fuel and Feedstock									
Producing Technologies			229.220						
Coal Preparation	58.408	36.730			3.904			3.976	13.798
Coal Mixtures/ Alternate Fuels	37.738	27.242					0.730	0.024	9.742
Liquifaction	1181.240	702.100						0.009	479.233
Surface Gasification	471.532	215.869				40.500	0.112	2.079	212.972
Underground Gasfication	45.443	35.633				4.000	0.768		5.042
Power and Energy									
Producing Technologies			239.625						
Atmospheric Fluidized Bed Combustors	156.428	21.050			82.610		1.364	4.003	46.312
Pressurized Fluidized Bed Combustors	85.121	69.260							15.861
Fuel Cells	308.903	179.300			0.178	63.300	0.662		65.465
Magnetohydrodynamics	184.874	177.961							6.913
Heat Engines	60.996	60.200					0.343		0.293
Environmental Pollution Reduction Technologies									
Flue Gas Cleanup	137.956	50.477		19.800	24.524		19.737	2.376	21.042
Gas Stream Cleanup	97.206	45.832		40.300			0.383	9.930	0.913
Advanced Combustors	16.607	7.723			0.200		0.099	1.107	6.990
Cross-Cutting Technologies									
Coal Waste Management	37.079	19.134			1.004	1.700		0.532	14.629
Advanced Research & Technology Development	297.576	217.049				4.900	0.603	5.115	82.057
Clean Coal R&D Program	1649.497	935.666	468.845	59.300	113.512	47.100	23.681	30.008	440.120
Other Coal	1535.986	917.049	0	0	0.178	67.7	1.42	0.009	540.74
Total	3185.483	1852.715	468.845	59.300	113.690	114.800	25.101	30.017	980.860

Figure 16

7 The U.S. is rapidly becoming the world's showcase for clean coal technology.

The federal Clean Coal Technology Demonstration Program is only one element of America's clean coal commitment. In preparing this report, DOE's Office of Fossil Energy compiled a nationwide inventory of clean coal technology development and demonstration efforts being financed by federal, state and private sources. The inventory was comprised of two major components:

(1) *Clean Coal Projects* -- large scale field demonstrations or tests of innovative clean coal technologies. In many cases (particularly for the privately-financed projects), the project was applicable to the electric utility sector. Also to be included in this compilation, a project had to represent a unique technological demonstration of a coal technology in terms of scale, application, coal type, etc. It had to demonstrate an attractive option for controlling SO_2 and/or NO_x, rather than just a new method for using coal. And it had to be receiving significant amounts of public or private funding in the 1986-1992 time period.

(2) *Research and Development Programs* -- efforts being conducted that either support the above projects or that address more advanced but less mature clean coal technologies.

Once U.S. programs and projects meeting these criteria were identified, the expected financial commitments by both public and private sponsors were extended from 1986 to 1992, based on documented information.

The result of this inventory showed that the U.S. will invest more than $6 *billion* between 1985 and 1992 to demonstrate an array of innovative clean coal technologies.

...the U.S. will invest more than $6 billion between 1985 and 1992 to demonstrate an array of innovative clean coal technologies.

Figure 17 shows the elements that make up this national clean coal program.

Approximately $4.9 billion of the $6 billion is made up of specific clean coal projects, i.e., projects that will operate at a sufficiently large scale to demonstrate the viability of the innovative technology. The remainder of the funding is

Planned Innovative Clean Coal Technology R&D and Demonstrations
($ in millions)

CATEGORY		FEDERAL	STATE	EPRI	PRIVATE	TOTAL	FY	REMARKS
FEDERAL	Federal Control Tech. R&D							
	DOE	738				738	86-92	Budget Projections
	EPA	21			7	28	86-92	Budget Projections
	Subtotal	759			7	766		
	Federal Demonstrations							
	DOE Clean Coal Prog-1	396	39		560	995	86-90	Projects in negotiations
	DOE Clean Coal Prog-2	150			150	300	88-90	Estimated as 50% co-funding
	DOE Clean Coal Prog-3	200			200	400	90-92	Estimated as 50% co-funding
	Other DOE Supported Projects	14	4		1	19	91-92	Allegan & Commonwealth Edison
	Environ. Protection Agency Projects	5			12	17	86-88	Tangentially Fired LIMB
	Dept. of Treasury Projects	480*	2	105	600	1187	86-92	DOW Syngas & Cool Water
	Tennessee Valley Authority Projects	67	10	81	82	240	86-92	160 MW AFBC, 20 MW AFBC & Spray Dryer/ESP
	Subtotal	1312	55	186	1605	3158		
	Federal Total	2071	55	186	1612	3924		
NONFEDERAL	State-Financed Clean Coal Projects Subtotal		253		124**	377	86-92	Illinois & Ohio Only
	Private Demonstrations							
	EPRI Privately Financed Projects			79	287	366	86-90	Five Projects
	Other Privately Financed Projects				1338	1338	86-92	
	Subtotal			79	1625	1704		
	Private Research & Development							
	EPRI R&D			103		103	86-90	
	GRI R&D				40	40	86-90	
	Subtotal			103	40	143		
	Nonfederal Total		253	182	1789	2224		
SUMMARY	Total U.S.	2071	308	368	3401	6148		

*Represents price guarantees to be paid out
**Co-funding not fully determined

Figure 17

comprised of privately and publicly financed research and development programs that are focused specifically on the cleaner use of U.S. coal.

Just over $2.0 billion of the national investment is represented by currently planned federal expenditures. The private sector's contribution will nearly double the federal share -- approximately $3.9 billion of which nearly $370 million will come from the Electric Power Research Institute (EPRI), the research arm of the utility industry.

State government funding will also make a significant contribution to the national total. While state-funded projects are underway in several States -- for example, West Virginia, Pennsylvania, Virginia, Kentucky and several other States are supporting clean coal research -- the States of Illinois and Ohio in particular have taken an aggressive role in financing large-scale development and demonstration efforts. The contribution from these two States alone amounts to more than $300 million.

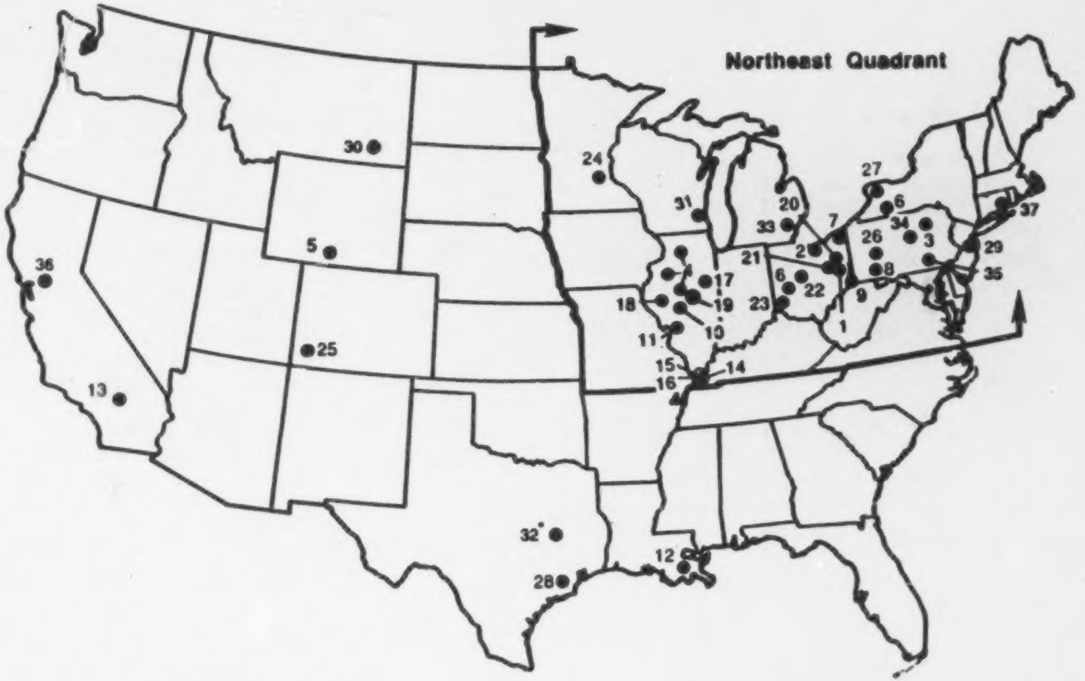
Appendix B describes in detail the programs and projects that make up this list of clean coal-related activities.

Figure 18 depicts the geographic dispersion of projects included in the $6 billion compilation. The concentration of projects is greatest in the Northeast quadrant of the U.S. The 29 projects located in this region have a total value of $2.5 billion, or 51% of the clean coal projects included in the compilation.

Many of the projects listed in this report are receiving, or are expected to receive, funding from several sources including federal, state and/or private sponsors. In compiling the national inventory listed below, projects were placed in categories that best describe the overall demonstration or test effort, i.e. DOE Clean Coal Technology Projects, Tennessee Valley Authority Projects, State-Financed Demonstration Projects, etc. The reader should recognize, however, that many projects in an individual category are also being partially funded by sponsors in other categories. For example, several projects in DOE's Clean Coal Technology Program will be co-funded by state governments. In compiling the listing, however, the Department ensured that none of the funding was "double-counted."

The concentration of [clean coal] projects is greatest in the Northeast quadrant of the U.S.

The specific projects that make up America's clean coal commitment are as follows:



Clean Coal Technology Projects

Northeast Quadrant
30
24
27
6
20
31
7
33
34
3
26
5
2
21
29
36
17
6
22
8
35
18
19
23
9
10
1
11
25
15
14
16
13
32
12
28

* Expected Site

Figure 18

Department of Energy Clean Coal Technology Projects

No.	Project	Site
1.	American Electric Power Service Corp. Pressurised Fluidised Bed Combustion Combined Cycle Utility	Brilliant, OH
2.	Babcock & Wilcox Tests of Limestone Injection Multi-Stage Burner & Sorbent Duct Injection	Lorain, OH
3.	Coal Tech Corporation Slagging Combustor with Sorbent Injection into Combustor	Williamsport, PA
4.	Energy & Environmental Research Corp. Reburning & Sorbent Injection in Utility Boilers	Springfield, Hennepin, & Bartonville, IL
5.	Energy International Inc. Underground Coal Gasification Integrated with Indirect Liquefaction	Rawlins, WY
6.	General Electric Company Integrated Coal Gasification with Steam Injection Gas Turbine with Hot Gas Cleanup	Evendale, OH & Dunkirk, NY
7.	Ohio Ontario Clean Fuels Inc. Coal-Oil Co-Processing Liquefaction	Warren, OH
8.	The M.W. Kellogg Company/Fluidised Bed Gasification with Hot Gas Cleanup Integrated Combined Cycle	Cairnbrook, PA
9.	Weirton Steel Corporation/Direct Iron Reduction to Replace Coke Oven Blast Furnace	Weirton, WV

Other Clean Coal Field Projects Receiving DOE Support

No.	Project	Site
10.	Commonwealth Edison/Copper Oxide Regenerable Flue Gas Desulfurisation System	Kincaid, IL
11.	Allis Chalmers/Kilngas Coal Gasification Project (co-funded with EPRI and State of Illinois)	Wood River, IL

Department of Treasury Projects (formerly financed by U.S. Synthetic Fuels Corp.)

No.	Project	Site
12.	Dow Chemical Co./Dow Syngas Coal Gasification Combined Cycle	Plaquemine, LA
13.	Cool Water Gasification Combined Cycle (construction privately financed)	Daggett, CA

Tennessee Valley Authority Projects

No.	Project	Site
14.	Tennessee Valley Authority/160 Megawatt Atmospheric Fluidised Bed Combustion Demonstration Plant	Paducah, KY
15.	20-Megawatt Atmospheric Fluidised Bed Combustion Pilot Plant	Paducah, KY
16.	Spray Dryer/Electrostatic Precipitator Pollution Control Device	Paducah, KY

State-Financed Clean Coal Demonstration Plants

17. University of Illinois - Wet Flue Flue Gas Desulfurization System	Champaign, IL
18. Anderson Clayton Foods Co./Dual Fluidized Bed Boiler Retrofit	Jacksonville, IL
19. Archer-Daniels-Midland/108-Megawatt Circulating Fluidized Bed Cogenerators (6)	Decatur, IL
20. Babcock & Wilcox (Ohio Edison's Toronto Station)/Post Combustion SO_2 Control	Jefferson, OH
21. Scio Pottery Co./Industrial Cogeneration	Scio, OH
22. Columbia Gas System Corp./Catalytic Reduction Process for Coal Flue Gas	Columbus, OH
23. Hudepohl Brewery Power House/ Industrial Rotary Cascading Bed Boiler	Cincinnati, OH

Privately Financed Projects with Electric Power Research Institute Involvement

24. Northern States Power Atmospheric Fluidized Bed Combustion Utility Conversion (Black Dog Unit #2)	Minneapolis, MN
25. Colorado-Ute Circulating Atmospheric Fluidized Bed Demonstration Plant	Nucla, CO
26. EPRI Coal Cleaning Test Facility	Homer City, PA
27. High Sulfur Test Center/New York Electric Gas	Somerset Station, Niagara, NY
28. Shell Oil Coal Gasification Demonstration Plant	Deer Park Complex, Houston, TX

Other Privately Financed Projects

29. New Jersey Energy Associates 140-Megawatt Cogeneration Plant Using Coal Derived Gas	Sayerville, NJ
30. Synfuels Genesis International & Dravo Corp./37-Megawatt Coal-Fired Cogeneration Plant	Colstrip, MT
31. Wisconsin Electric Power Company Atmospheric Fluidized Bed Retrofit of Four Coal-Fired Units (500 Megawatt total)	Oak Creek, WI
32. Texas-New Mexico Power Company Circulating Fluidized Bed Boiler Utility Retrofit	TBD (expected site in Robertson County, TX)
33. General Motors Corporation 27-Megawatt Circulating Fluidized Bed Cogeneration Unit	Pontiac, MI
34. Gilbertson Power Company Anthracite-Culm Fired Cogeneration Plant	West Mahoney Township, PA

35. Combustion Engineering & Lurgi Corp. 25-Megawatt Circulating Fluidised Bed Cogeneration Plant	Reading, PA
36. Air Products & Chemicals, Inc. 40-Megawatt Circulating Fluidised Bed Cogeneration Plant	Stockton, CA
37. Applied Energy Services 180-Megawatt Circulating Fluidised Bed Cogeneration Plant	Montville, CT

In addition to improving domestic energy security and environmental quality, the development and demonstration in the U.S. of these new technologies could offer major benefits to the marketing of American coals overseas.

Worldwide consumption of coal is expected to increase by more than one-third between now and the end of the century, primarily because of increasing coal-fired electric generating capacity.

Worldwide consumption of coal is expected to increased by more than one-third between now and the end of the century....

In Europe, for example, demand for coal is expected to increase by 30% with the largest tonnage increases taking place in Germany and Italy. Japan's consumption of coal is also expected to increase almost 50% by the end of the century, based entirely on growing demand for steam coal. Other nations in the Pacific Rim also project significant increases in coal consumption.

New coal markets are also opening in the less developed countries (LDC's). In fact, LDC's are expected to experience the fastest rate of increase in coal consumption, almost 60% between now and the year 2000.

...[less developed countries] are expected to experience the fastest rate of increase in coal consumption, almost 60% between now and the year 2000.

To meet this increasing demand, world coal trade is expected to expand by almost 50 percent by the year 2000.

As in the U.S., growth in the demand for coal by many industrialized and developing nations will likely be accompanied by increasing concerns over environmental impacts. The improved coal technologies being developed and demonstrated in the U.S. will be able to meet the environmental objectives of the international community.

Moreover, because America's clean coal projects will provide commercial-scale performance data using U.S. coals, the potential exists to link U.S. coal exports and U.S. technology in a way that enhances America's international competitiveness in both areas.

8 The Nation is meeting its commitment to a cleaner environment in concert with increasing the use of American coal.

Coal's abundance (80% of the nation's known fossil fuel resources) makes it one of America's most important strategic resources in building a more secure energy future. Coal can be one of the nation's most productive domestic energy sources well into the 21st Century and beyond. If coal is to reach its full potential, however, economically competitive, advanced coal-using systems must be developed which are sensitive to diverse energy markets and site-specific factors as well as stringent environmental requirements.

America's clean coal commitment has the potential to:

1. Control large amounts of the SO_2 and NO_x released from coal-fired power plants including those in the environmentally-sensitive Northeast.
2. Return economic benefits to American consumers by permitting clean energy to be generated without financially constraining capital investments for environmental controls.
3. Retrofit and repower aging coal-fired power plants, particularly those in the East.
4. Use high-sulfur coals, thereby avoiding the social disruptions associated with massive coal switching, and
5. Reduce acid rain related emissions -- especially from aging power plants in the nation's northeast quadrant.

How rapidly these innovative clean coal technologies will be deployed depends upon many factors. Two of the most important are (1) technology risk -- concern about the performance and reliability of the technologies; and (2) market demand -- influenced, for example, by the growth in demand for electricity and the future regulatory environment.

America's $6 billion clean coal commitment directly addresses the technological risk. By developing and demonstrating new technologies at commercial- or near-commercial scale, the risk of commercial deployment is reduced.

Market demand, however, is much more uncertain. Many of the emerging clean coal technologies are designed to generate electric power cleanly and more efficiently than is possible today.

There is little doubt that electricity is vital to the future of the U.S. The nation's health depends on continued economic growth, and if adequate electrical generating capacity is not available, we run the risk of undermining this growth.

Coal can provide much of the resource base to ensure continued economic progress. But utilities have been understandably reluctant in recent years to invest in large, conventional baseload power plants -- either coal or nuclear fueled. The uncertainty over anticipated growth in power demand, coupled with uncertainty regarding future environmental regulations, has stalled many construction projects.

In those regions of the country where the demand for electricity is expected to increase, utility owners will soon be faced -- if they are not already -- with the need to install new generating capacity. The need for additional electricity will likely intensify as we approach the mid-1990s when the majority of existing coal-fired power plants will turn 25 or more years old.

The need for additional electricity will likely intensify as we approach the mid-1990s when the majority of existing coal-fired power plants will turn 25 or more years old.

At that point, utilities must consider various options for continuing to produce power from these aging facilities or alternatively, to shut them down.

These events -- today's slowdown in construction and the anticipated future demand for new facilities, either "grassroot" plants or as replacements for older units -- have combined to create a "window" for new clean coal technologies that will open even wider in the 1990s.

For those utilities that face the dual problem of aging baseload power plants and the need for additional electricity, the *repowering* technologies -- integrated gasification combined cycle, pressurized and atmospheric fluidized bed combustion -- are especially attractive options. They can be installed relatively quickly (compared to construction of a new baseload plant) and in a modular fashion. This would allow a utility to carry out its construction program in smaller increments to meet projected demand growth. And it will help ensure that consumers are not confronted with another cycle of "rate shock" caused by bringing large, new baseload plants into service.

For utilities facing the dual problem of aging baseload power plants and the need for additional electricity, repowering technologies are especially attractive.

With these repowering technologies, utilities can use much of the equipment in the aging plant, increase its power output by as much as 150 percent, extend its useful lifetime, and greatly reduce SO_2 and NO_x emissions. The technologies are relatively insensitive to coal type and can be installed on most existing coal-fired power plants.

Those utilities confronted with possible requirements for further emission controls will also benefit from the emergence of an expanded slate of *retrofit* clean coal technologies.

Today, if more stringent environmental controls were to be imposed on existing facilities, utilities would be limited to three options -- flue gas scrubbing which is very costly, switching to low-sulfur coals which could create severe socio-economic impacts, and coal cleaning which is limited in reducing SO_2 emissions.

The expanding slate of innovative clean coal retrofit technologies should provide substantially improved options that are preferable to the choices available today. These new technologies offer the flexibility to be used individually or in combination with one another to achieve emissions control of both SO_2 *and* NO_x. They provide cost-effective options for the diverse inventory of coal-fired power plants, including those that are limited in available space. They permit the full range of coals to be used in small, moderate or large size boilers. And they produce waste products that are more easily and safely disposable or, in some cases, saleable.

Finally, the availability of demonstrated clean coal hardware can give America a substantial marketing advantage overseas. The "packaging" of U.S. coal and the technology to use it cleanly and efficiently can provide an important boost to the competitiveness of America's coal industry.

America's clean coal commitment is real and substantial. It comes at a time when the nation's environmental consciousness -- and that of our global neighbors -- is again on the rise. It also coincides with the national goal established by the President in his 1987 State of the Union Address: Assure American competitive preeminence into the 21st Century.

The "packaging" of U.S. coal and the technology to use it...can provide an important boost to the competitiveness of America's coal industry.

Perhaps most importantly, America's clean coal commitment represents a public and private sector partnership that can make coal an environmentally attractive fuel for the future, a fuel for energy security, and a fuel for continued economic growth.

February 1987

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Appendix A

AMERICA'S
CLEAN COAL
COMMITMENT

U.S. DEPARTMENT OF ENERGY

FEBRUARY 1987

Appendix A

Introduction

This Appendix describes the following technologies which were discussed in the briefing: the conventional coal-fired power plant with particulate removal devices only; the conventional coal-fired power plant with flue gas scrubber; and the innovative clean coal technologies.

The Appendix is organized in a side-by-side format; that is, the narrative is presented on the left-hand page, and a diagram of the corresponding technology is presented on the right-hand page.

Conventional Coal-Fired Electric Power Plant

How Does It Work?

The conventional coal-fired power plant, which is usually equipped with particulate removal devices only, is used as the base technology in this briefing. The sulfur emissions from this type of plant are tied to the sulfur content of its coal feed. The subsequent technologies described in this Appendix involve SO_2/NO_x emission control procedures. These technologies are compared with the base technology to highlight their attributes in terms of their SO_2 and NO_x removal abilities and associated costs.

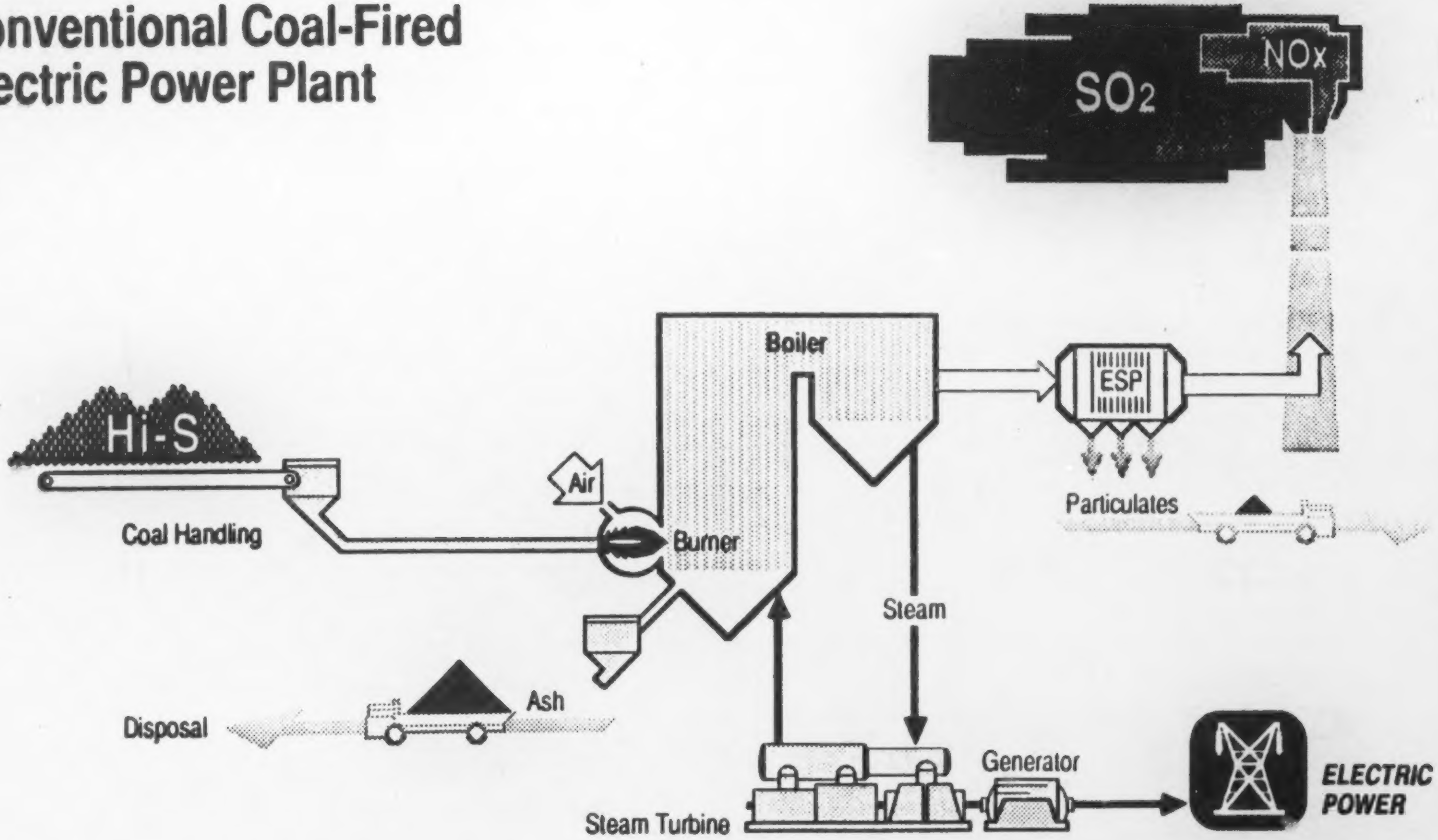
Conventional coal-fired power plants may vary in size from less than 100 MW to more than 2000 MW and may be used in base-load and/or intermediate-load applications. The efficiency of the energy conversion from raw coal feed to the production of electricity is 35-38 percent. The cost of capital for a new plant in the 350-1000 MW size is from $1,500-$1,800 per kw. With routine maintenance, a plant is expected to perform at design specifications for about 30 years. The operating and maintenance costs range from 15-25 mills per kwh. The net heat rate for conventional plants range from 9,000-11,000 Btu per kw.

Coal combustion may be carried out in pulverized coal burners, cyclone furnaces, or various stoker and grate arrangements. In pulverized coal boilers, pulverized coal is blown into the furnace. A significant amount of the incombustible fines leave with the combustion gases as fly ash, and the remainder is collected as bottom ash. In cyclone furnaces, coal is fed into the furnace tangentially, which increases the residence time and promotes thorough combustion. However, the increased combustion temperatures also result in increased NO_x formation. In stoker-fired boilers, coal enters the firebox on moving grates. The combustible gases ignite and generate steam in the boiler. The solids continue to burn as they travel through the furnace toward the ash collector at the end of the grate.

Heat from the combustion gases is transferred to the water circulating in the boiler tubes. After a series of heat exchange operations within the boiler, saturated or superheated steam is generated. This steam then expands through a steam turbine, its velocity increases, and its temperature and pressure decrease. The high velocity steam impinges on the turbine blades causing rotation. The mechanical energy from the turbine is converted to electrical energy by the generator.

Conventional boilers have either a wet or dry bottom. In wet bottom design, when coal is burned,ash becomes molten and runs to the bottom of the boiler. Hence, these boilers require coal with low ash fusion temperature. In contrast, in boiers with dry bottom designs, coal ash is not supposed to liquefy; so, these boilers require coal with high ash fusion temperatures. Power plant coal pulverizers are also designed for specific types of coal. If an alternative coal is more difficult to grind or contains too much ash, then the pulverizer cannot provide adequate fuel to the boiler. Although coal sulfur content does not significantly impact combustion, it does impact the performance of electrostatic precipitators. For coals containing less than 1 percent sulfur, performance of an electrostatic precipitator designed for high sulfur coals becomes less effective.

Conventional Coal-Fired Electric Power Plant


SO2
NOx
Hi-S
Coal Handling
Air
Burner
Boiler
ESP
Particulates
Steam
Ash
Disposal
Steam Turbine
Generator
ELECTRIC POWER

Flue Gas Scrubber

How Does It Work?

Flue gas scrubbing is a commercial technology that has been utilized in many power plants, especially those burning high-sulfur coal. It involves reduction of SO_2 from the combustion flue gases prior to atmospheric emissions by chemical reaction with alkaline sorbents.

In a wet flue gas scrubber, the gas produced in coal combustion is typically sprayed with a slurry made up of water and an alkaline reagent, usually limestone. The SO_2 in the flue gas reacts chemically with the reagent in the slurry forming calcium sulfite and/or calcium sulfate, which is removed and disposed of in the form of a wet sludge having the consistency of toothpaste. This wet sludge is composed of calcium sulfite, calcium sulfate, water, and unreacted limestone.

Scrubbers have been widely deployed, some removing more than 90 percent of the SO_2 emissions from high-sulfur coals. Scrubbers are relatively costly to install and may cost as much as $250 per kw capacity. Also, a flue gas scrubber is costly to operate. It consumes from 5-8 percent of the plant's output to run pumps, fans, and a flue gas reheat system. It has high maintenance costs and consumes a large amount of water (500-2500 gallons per minute for a 500 MW unit). Further, there are reliability problems due to plugging and fouling of the equipment and corrosion of fans and downstream ductwork. Large space is required to handle scrubber waste--typically one acre-foot per MW per year.

An alternative approach is the dry scrubber, or spray dryer. In a dry scrubber, the reagent slurry--usually lime--is injected into an absorber vessel in a finely atomized form. The droplets evaporate in the hot gas, leaving only dry, reacted particles for collection in a conventional baghouse or electrostatic precipitator.

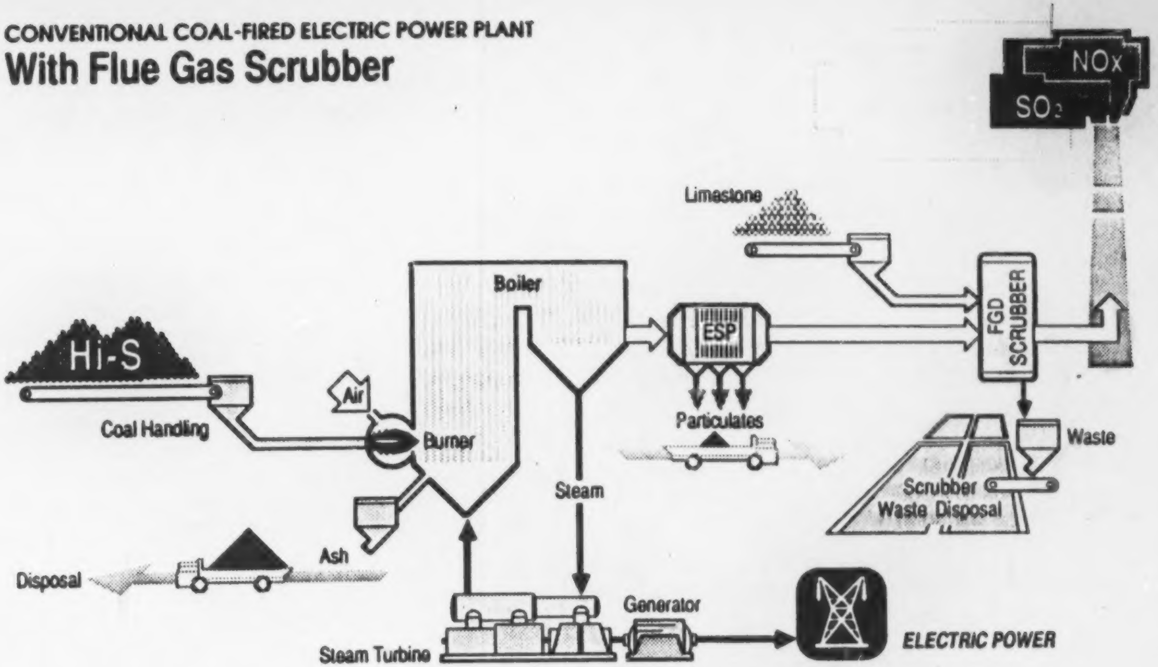
Although the dry scrubber is simpler, it has not been used successfully on high-sulfur coal which may require 90 percent control. A dry scrubber may, in fact, be more costly than a wet scrubber, due to the increased cost of the reagent, for grass roots installation.

What Are Its Attributes?

- The wet flue gas scrubber can achieve over 90 percent SO_2 removal from flue gases. However, it is costly to install, operate, and maintain.
- NO_x emission is not affected by a wet or dry flue gas scrubber.
- Flue gas scrubbing reduces the overall efficiency of a coal-fired power plant from 35-38 percent to 32-35 percent .
- Large amounts of scrubber sludge are produced (in the order of 1 acre-foot per MW per year). Therefore, sludge handling requires large amounts of space.

CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

With Flue Gas Scrubber


NOx
SO2
Limestone
Boiler
ESP
FGD SCRUBBER
Hi-S
Air
Coal Handling
Burner
Particulates
Waste
Scrubber Waste Disposal
Steam
Ash
Disposal
Generator
ELECTRIC POWER
Steam Turbine

*COMPARED WITH CONVENTIONAL TECHNOLOGY**

SO_2 EMISSION REDUCTION	NOx EMISSION REDUCTION	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
90% AND HIGHER	No Change	Decrease	Moderate Decrease	No Change	9–11 MILLS/KWH	$180–200 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

Advanced Flue Gas Cleanup

How Does It Work?

There is a great deal of activity involved in the development of advanced flue gas cleanup devices. A number of processes are under development. Examples of the types of processes under development include the use of electron beam radiation for process enhancement and the use of metal oxides both for SO_2 control and as a catalyst for the selective catalytic reduction of NO_x by ammonia. These processes are primarily applicable to grass roots units but may also prove useful for the retrofit of existing units.

The copper oxide fluidized bed process is undergoing proof of concept testing at the present time. Alumina spheres are coated with copper oxide and suspended in a bed that is fluidized using the flue gas laden with SO_2 and NO_x. The copper oxide reacts with SO_2 to produce copper sulfate, which is combined with natural gas to regenerate the copper oxide. The NO_x reacts with ammonia (in the presence of copper sulfate, which serves as a catalyst) to produce molecular nitrogen. The moving bed contactor, also under development, is less mature but potentially cheaper than the fluid bed contactor.

Electron Beam Processes present alternate approaches that appear to be attractive. Irradiation of flue gas with electron beams produces, under the proper temperature and humidity conditions, an abundant supply of free radicals, ions, monoatomic species, and secondary electrons which promote the oxidation of SO_2 and NO_x to sulfuric and nitric acids, respectively. Two separate processes based on this phenomenon have been under development. The first uses a lime spray dryer upstream of the electron beam chamber. The second uses ammonia injection to react with the acids and form ammonium salts.

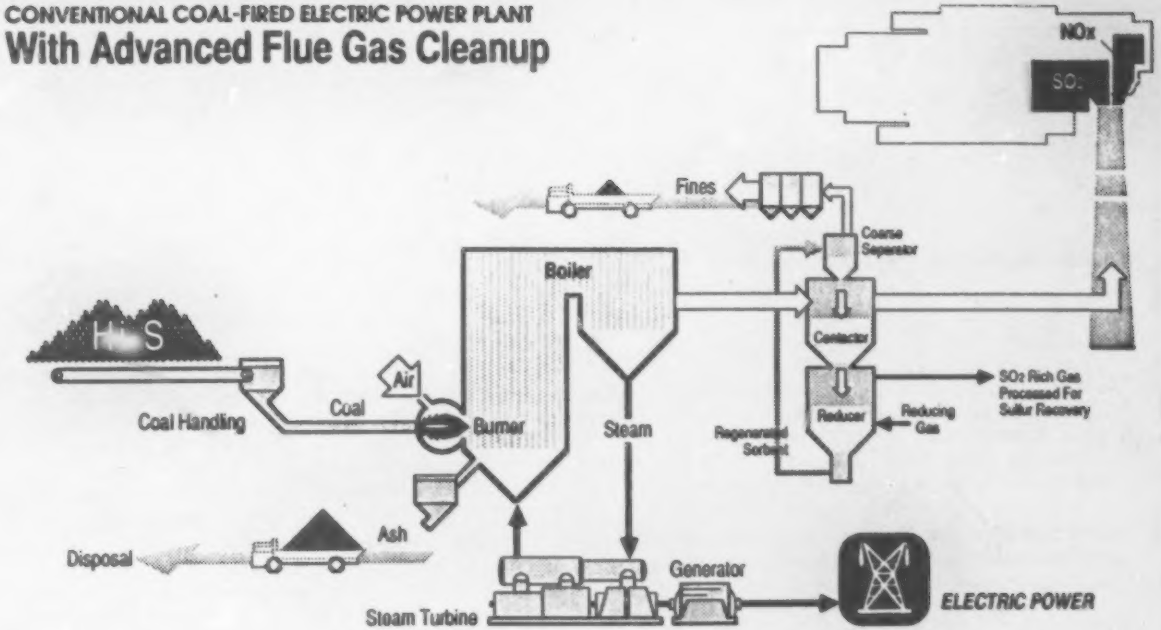
In the first approach, part of the reaction is between the flue gas and lime slurry in a spray dryer. Efficiency is improved in an electron beam chamber, and the reactions are completed in a fabric filter baghouse. In the second approach, the flue gas is irradiated in the presence of ammonia.

What Are Its Attributes?

- It is capable of reducing SO_2 and NOx emissions by 90 percent.
- It is capable of achieving high reductions in NO_x emissions; more than other retrofit technologies.
- While initially developed for new applications, it can be economically competitive in certain retrofit applications, particularly where deep NO_x removal is required.
- It is capable of either regenerating the sorbent or producing a fertilizer (E-beam ammonia).
- Unlike flue gas scrubbers, it does not produce large quantities of scrubber sludge. Hence, even though the capital costs are in the same range as those for flue gas scrubbers, the overriding advantages are many.

CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

With Advanced Flue Gas Cleanup


NOx
SO_2
Fines
Coarse Separator
Boiler
H S
Air
Coal Handling
Coal
Burner
Steam
Contactor
Reducer
Reducing Gas
Regenerated Sorbent
SO_2 Rich Gas Processed For Sulfur Recovery
Ash
Disposal
Generator
Steam Turbine
ELECTRIC POWER

		COMPARED WITH CONVENTIONAL TECHNOLOGY*				
SO_2	NOx					
EMISSION REDUCTION		PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
90% AND HIGHER	High	Decrease	Small Decrease	No Change	10–12 MILLS/KWH	$175–190 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

Limestone Injection Multistage Burner or Slagging Combustor

How Does It Work?

The slagging combustor is an advanced device that will control or remove objectionable sulfur and particulate matter from coal-derived fuel before it is injected into retrofitted boilers or heaters. Although these combustors are primarily intended for retrofit applications, they will also be applicable and appropriate for incorporation into the design of new facilities that can utilize their compact size and flexibility of coal use. The limestone injection multistage burner (LIMB) approach is identical in application to retrofit and new installations as is the slagging combustor. The coal, either as a dry pulverized fuel or as a coal liquid mixture, is fed into the combustor in the conventional manner (pulverized coal firing) or pumped under pressure and injected as a slurry.

In the slagging combustor, the fuel is injected radially from a central injector, whereas the air is fed tangentially around the periphery. The interaction of the air moving circumferentially and the coal particles or droplets moving axially and radialy outward results in a continuous flow of air across a burning particle, thereby providing more rapid and efficient combustion of the coal. Points of air injection can be placed in such a manner as to provide staged combustion to control NO_x formation.

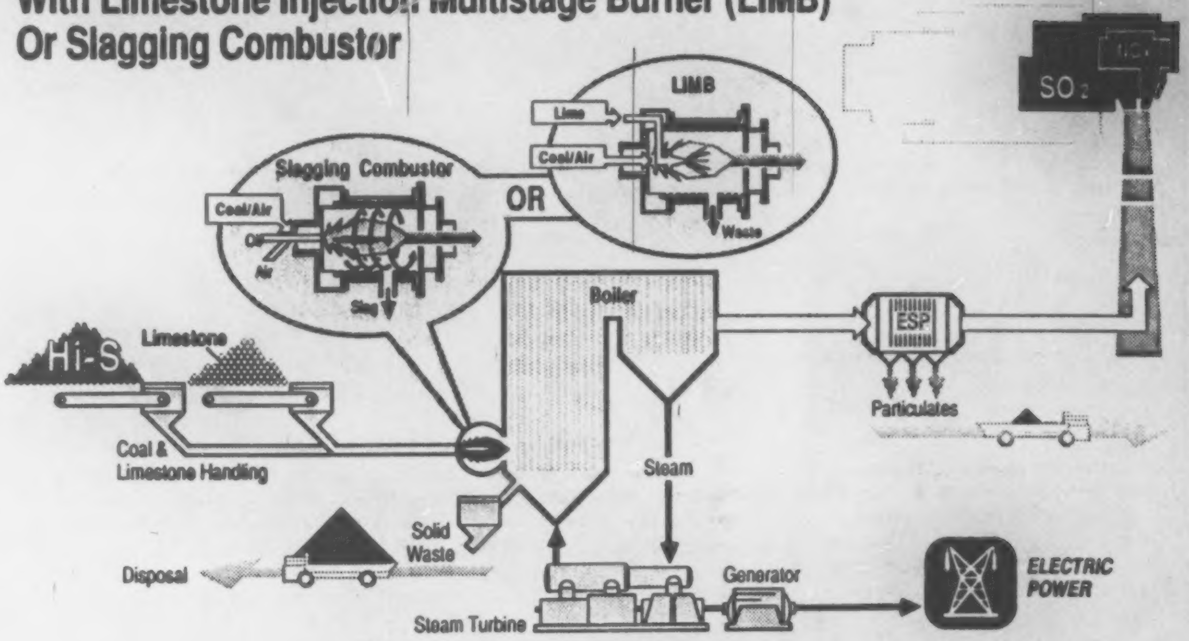
Sulfur dioxide control is achieved by the injection of alkali compounds, e.g., limestone, during combustion or with the fuel. The slagging combustor controls particulate emission by converting the ash into molten slag which, together with the solid sulfites and sulfates produced by the injection of limestone, are removed before the hot gases enter the boiler or heater passage areas. In the LIMB, the limestone is introduced into the combustor or into the combustion gases of a burner operating at a temperature that produces dry ash. The particulates, including the reacted sorbent and sulfur, are carried through the boiler passageways and subsequently captured by either a baghouse or electrostatic precipitator before exhausting the flue gas to the atmosphere through the stack.

What Are Its Attributes?

- There are no special coal handling requirements other than the addition of a limestone feed system.
- The slagging combustor produces a molten slag containing the ash and captured sulfur as a solid waste prior to boiler entry.
- The removal of ash as slag rejection is 80-90 percent.
- NO_x reduction is achieved by staged combustion.
- NO_x reduction of 50-70 percent relative to wall-fired, pulverized-coal combustors is achieved.
- Slagging combustors have the potential to replace existing cyclone boilers, which are very high NO_x emitters.
- Coal liquid fuel can simplify fuel storage, handling, and feed systems.
- Injection of sulfur sorbent either with the fuel or separately into the combustor or into the combustion gases eliminates the need for a flue gas desulfurization system.
- High-sulfur, high-ash, and low-fusion temperature coals can be used.

CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

With Limestone Injection Multistage Burner (LIMB) Or Slagging Combustor


LIMB
Lime
Coal/Air
Waste
OR
Slagging Combustor
Coal/Air
Oil
Air
Slag
Hi-S
Limestone
Coal & Limestone Handling
Boiler
Steam
ESP
Particulates
SO2
Solid Waste
Disposal
Steam Turbine
Generator
ELECTRIC POWER

*COMPARED WITH CONVENTIONAL TECHNOLOGY**

	SO_2	NOx	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
	EMISSION REDUCTION						
LIMB	50–60%	Moderate	Decrease	Small Decrease	No Change	5–8	$80–110
SLAG. COM. . . .	50–90%	Moderate	Small Decrease	Small Decrease	Slight Extension	1–2 MILLS/KWH	$50–60 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

Gas Reburning and In-duct Sorbent Injection

How Does It Work?

Gas reburning uses a small amount (10-20 percent of total fuel input) of natural gas which is injected above the normal heat release zone of the furnace to form an oxygen deficient zone. The NO_x produced in the primary heat release zone is "reburned" in the oxygen deficient zone and partially reduced to molecular nitrogen. Finally, burnout air is introduced above the reburning zone to complete the combustion process. Since the natural gas contains neither sulfur nor ash, emission of both are reduced in direct proportion to the amount of gas used.

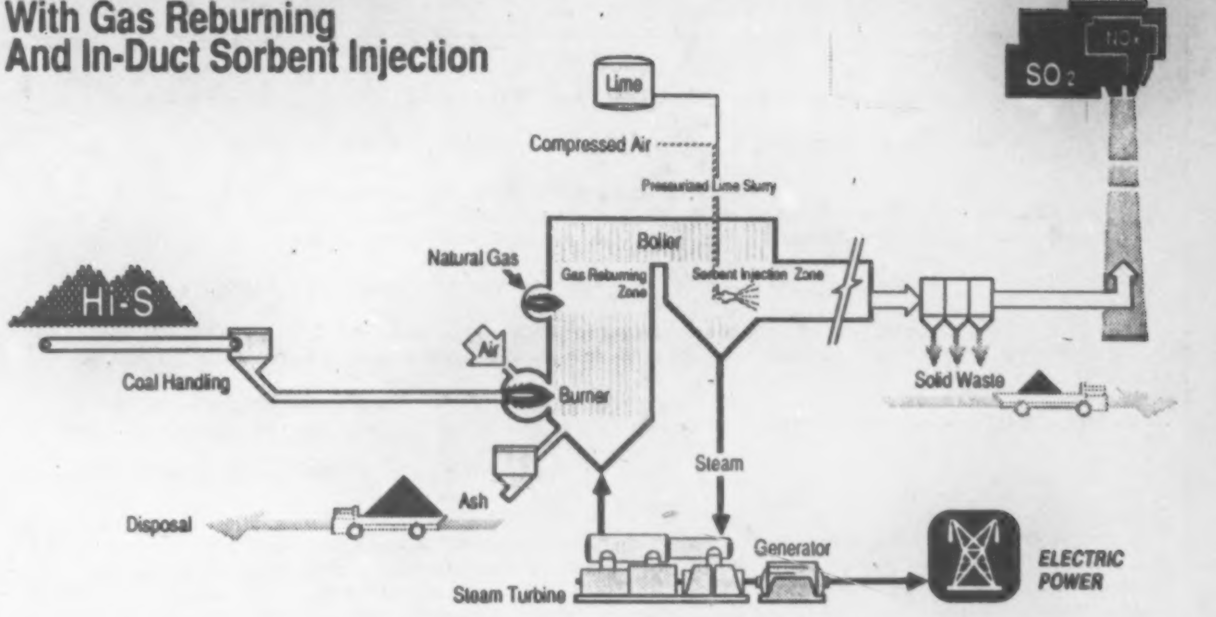
In-duct sorbent injection involves the spray injection of calcium based sorbents close to the center of the duct and downstream from the combustion zone. The direction of the injection is cocurrent with the gas flow, and as the cone of spray expands, the gas within the cone cools and the SO_2 is rapidly absorbed by the spray droplets. The finer the sorbent droplets, the more reactive they are. Several in-duct sorbent injection processes are under development. The mode of spraying, the position of the spray mechanism in the duct, and the nature of the sorbent may vary depending on the process. However, the basic principles of all processes are similar. Captured as dry calcuim sulfate particles, SO_2 is removed in the downstream particulate collection equipment along with the flyash and the unreacted sorbent.

What Are Its Attributes?

- A moderate amount of SO_2 and NO_x reduction is obtained at a cost that is significantly less than the cost to use a scrubber.
- A dry and nontoxic solid waste is produced that can be disposed of easily.
- It can easily be retrofitted to an existing unit without requiring a major investment or a lengthy outage.
- While there is a small decrease in efficiency due to the small amount of energy needed to operate the equipment, there is an improvement in the operation of the boiler because of the reduced loading of ash into the boiler.

CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

With Gas Reburning And In-Duct Sorbent Injection



Lime
Compressed Air
Pressurized Lime Slurry
SO2
NOx
Boiler
Natural Gas
Gas Reburning Zone
Sorbent Injection Zone
Hi-S
Air
Coal Handling
Burner
Solid Waste
Steam
Ash
Disposal
Generator
Steam Turbine
ELECTRIC POWER

SO_2	NOx	COMPARED WITH CONVENTIONAL TECHNOLOGY*				
EMISSION REDUCTION		PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
55–75%	Moderate	Small Decrease	Small Decrease	Slight Extension	2–4 MILLS/KWH Plus Gas Price Factor For Reburning	$50–110 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

Advanced Coal Cleaning

How Does It Work?

Sulfur exists in coal in two basic forms, commonly called pyritic and organic. Pyritic sulfur is iron pyrite which exists in the coal as discrete small particles. Because this mineral looks like gold, it is sometimes referred to as "fool's gold." Organic sulfur is composed of sulfur molecules chemically bound to the complex coal molecule. Of the coal which is burned today, approximately 35 percent is cleaned by conventional coal cleaning plants. Conventional cleaning extracts the heavier forms of mineral matter, such as ash and pyritic sulfur, from the coal. Since the coal is lighter than the ash and pyrite, it can be essentially "floated" and thereby separated. However, none of the organic sulfur is removed by these conventional processes. For those coals cleaned, the sulfur reduction ranges from 10-30 percent depending on the parent coal and the cleaning technology applied. Coal cleaning technologies can be grouped into two categories: physical and chemical. Physical cleaning technologies, such as those being used commercially today, separate the ash and pyritic sulfur from the coal using physical differences. Therefore, the reduction of sulfur emissions is limited to the percent of pyritic sulfur in the coal. Chemical and microbial coal cleaning involves the introduction of chemical or microbial agents which react with the sulfur, including organic sulfur, ash, and sometimes the coal itself, to remove ash and sulfur. No chemical or microbial coal cleaning technology is now in commercial use.

What Are Its Attributes?

- Chemical cleaning has the potential of removing over 90 percent of the sulfur from coal, but the processing costs are greater than the costs of physical techniques.

- Reduced ash levels and improved coal quality have the potential of helping to offset the costs of cleaning the coal (e.g., reduced transportation costs, and improved powerplant availability and reliability due to reduced ash levels).

- New coal cleaning plants would typically be built near coal mines.

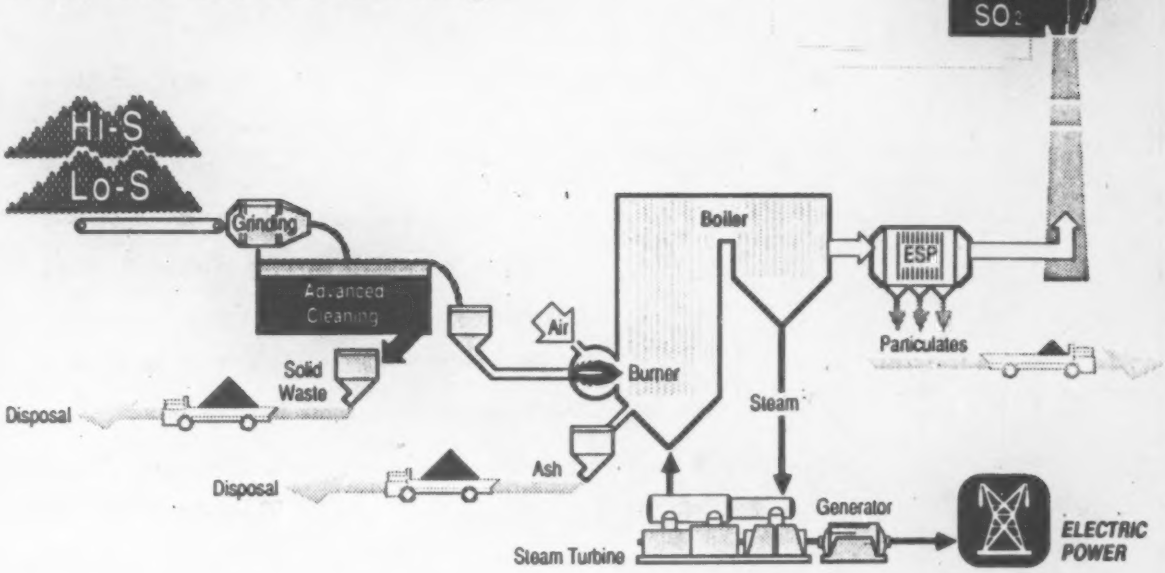
- Advanced physical cleaning technologies include several processes with the potential of removing 65 percent of the total sulfur in coal. The chemical technologies range from treatment with hot caustic (capable of removing 90 percent of the sulfur and 98 percent of the ash) to removal of organic sulfur using microorganisms.

- The waste from coal cleaning consists of solid mineral matter and is typically disposed of at the mine site.

- As nitrogen oxides are formed during combustion, coal cleaning does not reduce NO_x emissions.

CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

With Advanced Coal Cleaning


NOx
SO2
Hi-S
Lo-S
Grinding
Advanced Cleaning
Solid Waste
Disposal
Air
Burner
Boiler
Ash
Disposal
ESP
Particulates
Steam
Steam Turbine
Generator
ELECTRIC POWER

*COMPARED WITH CONVENTIONAL TECHNOLOGY**

SO_2 EMISSION REDUCTION	NOx EMISSION REDUCTION	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
30–90%	No Change	Small Increase	No Change	Slight Extension	6–21 MILLS/KWH	Additional Fuel Cost Only

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

Coal-Liquid Slurry Fuel

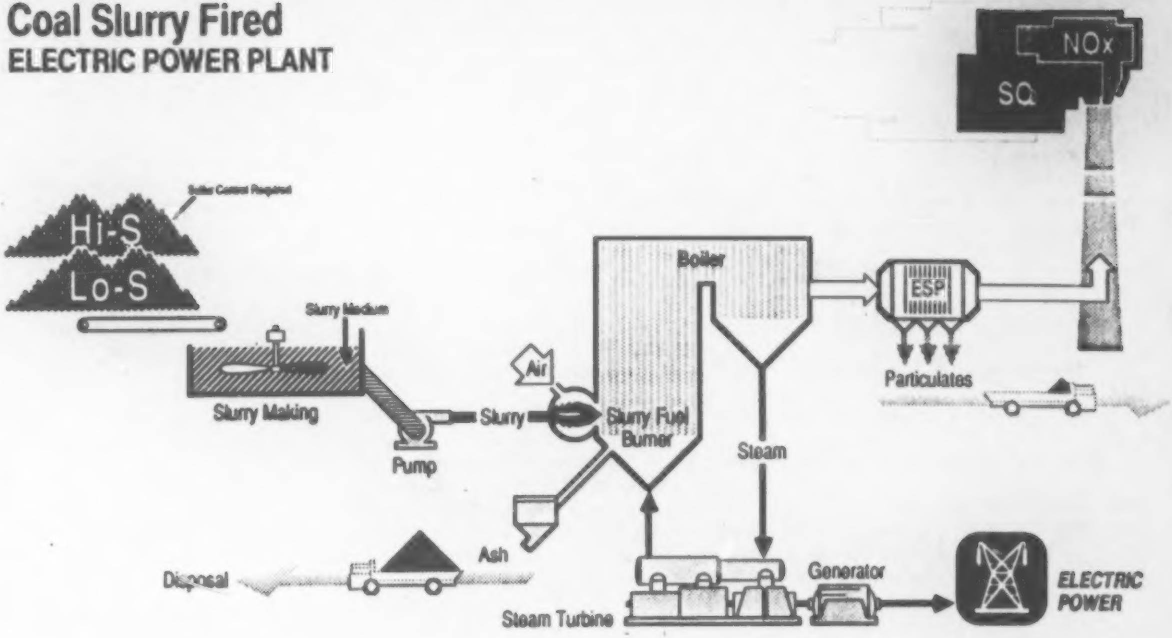
How Does It Work?

The slurry fuel burning system is not unlike a pulverized coal-fired boiler, except that its feeding operation is easier and its fuel relatively cleaner. Coal in the form of a slurry is pumped under pressure into the burner manifold where it is injected into the combustion chamber. With the proper combustor design, high combustion efficiencies can be achieved. Use of coal slurry fuels will not have any significant adverse effect on system efficiency nor any adverse effect on unit life. The preparation and use of a coal slurry fuel may increase the cost of utilization; however, the advantages of coal slurry fuels, i.e., transportability, ease of handling, safety, ease of feeding into the combustor, use of cleaner coal resulting from the fuel preparation process, etc., may offset the effects of increased utilization costs. Use of coal slurries prepared from standard pulverized coal will necessitate the same pollutant control processes as with pulverized coal-fired systems. However, most coal slurry fuels are produced as clean fuels, thus reducing to a minimum the pollution control requirements at the user site.

What Are Its Attributes?

- The fuel preparation process achieves significant reductions in SO_2 and particulate emissions.
- It is possible to reduce SO_2 emissions by more than 60 percent.
- It significantly reduces the quantity of waste produced at the user site.
- It eliminates coal pile run-off pollution control requirements.
- It provides ease of transport, storage, handling, and feeding.
- Increased injection pressures permit better fuel dispersion and, subsequently, higher combustion intensity and, therefore, unit size reduction.
- It provides for direct use in slurry form of wet coals produced from coal cleaning processes, without the added cost of coal drying required for pulverized feed systems.
- It significantly simplifies the feed system of a pressurized fluidized bed combustion system.

Coal Slurry Fired
ELECTRIC POWER PLANT


NOx
SO2
Hi-S
Lo-S
Slurry Medium
Slurry Making
Pump
Slurry
Air
Slurry Fuel Burner
Boiler
ESP
Particulates
Steam
Ash
Disposal
Steam Turbine
Generator
ELECTRIC POWER

COMPARED WITH CONVENTIONAL TECHNOLOGY*

SO2 EMISSION REDUCTION	NOx EMISSION REDUCTION	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
10–90%	No Change	Small Decrease	Small Decrease	No Change	11–23 MILLS/KWH	$20–50 PER KW

* CONVENTIONAL COAL FIRED ELECTRIC POWER PLANT

Integrated Gasification Combined Cycle (IGCC)

How Does It Work?

In a gasification reactor, coal is reacted with air and steam at a high temperature. This causes the coal to be converted to a gas composed predominantly of hydrogen, carbon monoxide, and hydrogen sulfide. The ash, which is not gasified, can then be easily separated. The sulfur in the coal is converted into hydrogen sulfide which eventually can be converted to elemental sulfur or some solid waste material. The cleaned gas stream is combusted in a gas turbine. While the gas turbine is similar to jet engines that power an aircraft, it is specifically designed to run electrical generators. The combusted gases which exit the gas turbine are still hot enough to generate steam which can then run a steam turbine to produce additional electricity. The name "combined cycle" is derived from the fact that both gas and steam turbines are in the system.

What Are Its Attributes?

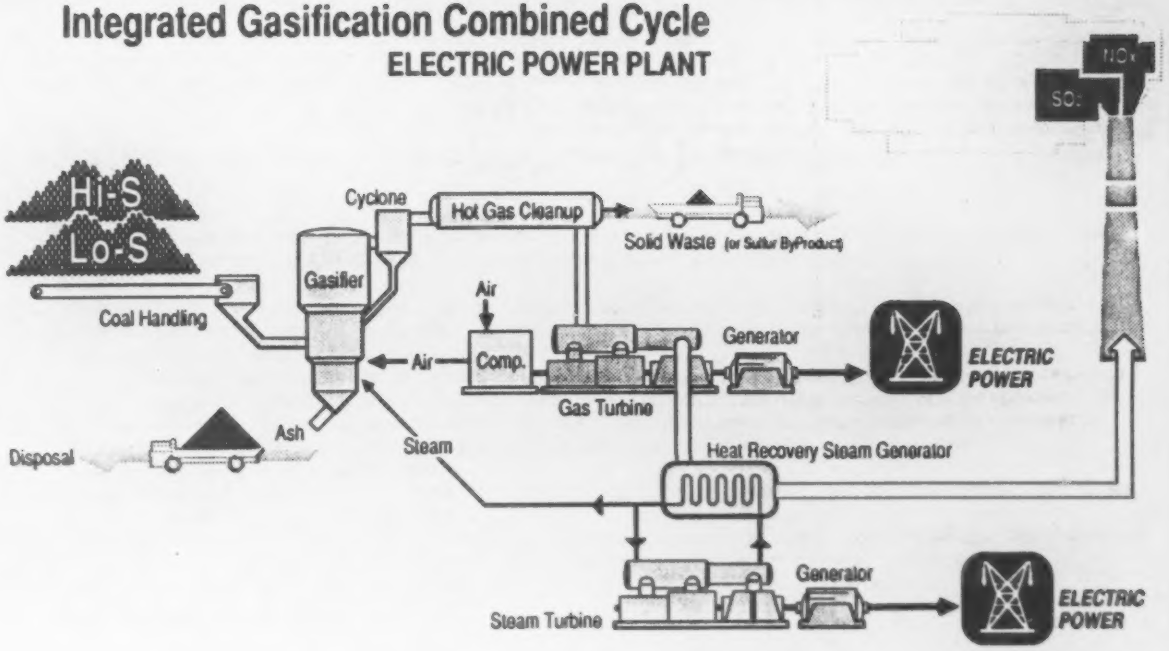
- There are no special coal handling requirements other than the potential to add limestone to the coal feed.
- Gases require hot particulate and sulfur cleanup before entering the gas turbine. No flue gas cleanup is required.
- Combined cycle plants, in addition to increasing the efficiency of energy production, can be composed of standardized modules in 100-200 MW sizes applicable to large and small utilities. This leads to easier installation, less construction time, and relatively lower cost without the usual economy of scale penalties.
- The waste generated is a dry, benign solid that can be disposed of easily or usefully employed (e.g., elemental sulfur or material for road or building construction).
- The space required for IGCC expansion is of the same order of magnitude as would be required for a scrubber.
- It is relatively non-sensitive to coal feedstock.
- Sulfur removal levels of over 99 percent have been demonstrated. These emission levels are well below the existing emission standard of 90 percent removal for new plants.
- Nitrogen oxide removal levels of 40 percent have been demonstrated.

What Repowering Potential Does IGCC Have For Targeted Plants?

In repowering with IGCC, a gasifier, gas stream clean-up unit, gas turbine, and waste heat recovery boiler are added; in most cases, these replace the existing coal boiler. The remaining equipment is left in place, including the steam turbine and electrical generator. The result is an extension of plant life to essentially that of a new plant, an increase in efficiency from a nominal 35 percent to over 40 percent, and an increase in overall plant output of 50-150 percent with significantly reduced overall emissions. The incremental cost of the additional capacity is low compared to the cost of a new plant.

Integrated Gasification Combined Cycle

ELECTRIC POWER PLANT


NOx
SO₂
Hi-S
Lo-S
Cyclone
Hot Gas Cleanup
Solid Waste (or Sulfur ByProduct)
Gasifier
Coal Handling
Air
Comp.
Air
Generator
ELECTRIC POWER
Gas Turbine
Ash
Disposal
Steam
Heat Recovery Steam Generator
Generator
Steam Turbine
ELECTRIC POWER

COMPARED WITH CONVENTIONAL TECHNOLOGY*

SO_2	NOx					
EMISSION REDUCTION		PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
95–99%	Moderate	Moderate Increase	50-150% INCREASE	Moderate Extension	1–2 MILLS/KWH	$1,100–1,300 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

Pressurized Fluidized Bed Combustion

How Does It Work?

Pressurized fluidized bed combustion (PFBC) utilizes a furnace in which a bed of coal and limestone (sorbent) is suspended in a stream of upward flowing pressurized air. The suspended particles behave like a fluid. During combustion, tubes with flowing water that are located within the bed are heated to form steam. The steam generated is then sent to a steam turbine for the generation of electricity. Increased system efficiency is realized by combined cycle operation through the incorporation of a gas turbine to recover additional energy from the pressurized products of combustion. A distinctive aspect of fluidized bed combustion is that when coal and a sorbent are injected into the bed, SO_2 reacts with the sorbent to produce a dry and benign solid.

What Are Its Attributes?

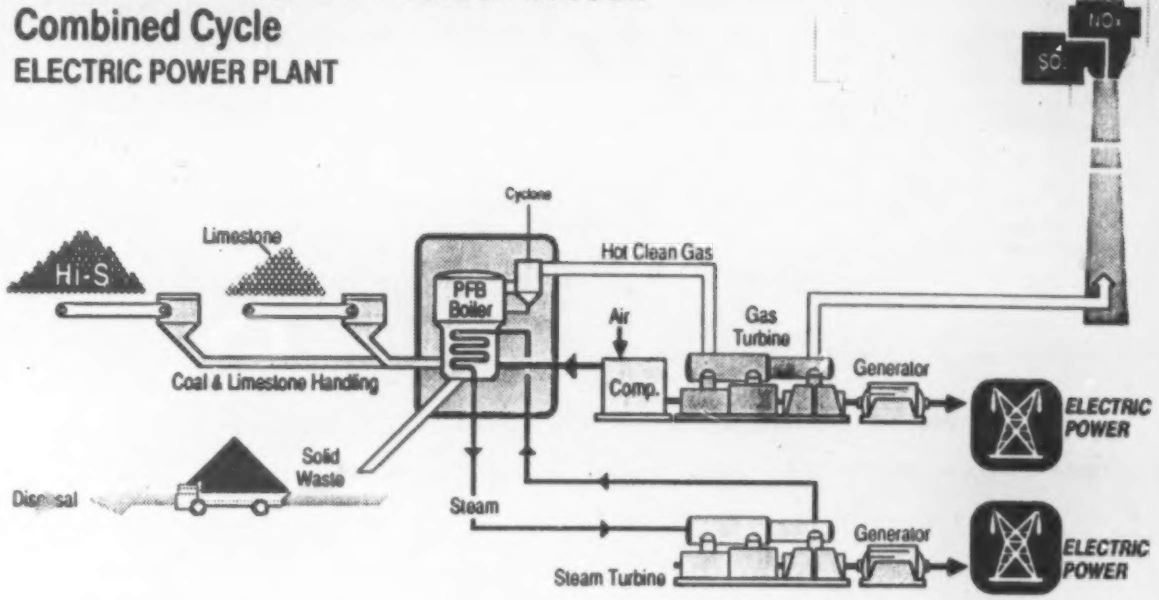
- There are no special coal handling requirements other than the addition of limestone to the coal feed.
- Gases require hot particulate cleanup before entering the gas turbine. No flue gas cleanup is required.
- The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the in situ capture of sulfur dioxide, eliminating the need for add-on removal units.
- The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures. This results in the reduced formation of nitrogen oxides.
- Elevated pressures permit higher combustion intensity and reduce the size of the unit.
- Combined cycle plants, in addition to increasing the efficiency of energy production, can be composed of standardized modules. This leads to ease of installation and a relatively lower cost without the usual economy of scale penalties.
- Modularity provides for staged construction which permits smaller increments of capacity, thereby shortening construction time and lowering financing requirements.
- The space required for PFBC expansion is of the same order of magnitude as would be required for a flue gas scrubber.
- Combustion occurs at temperatures below the ash melting point so that solids accumulation and boiler tube erosion and corrosion are minimized.
- Since it is relatively non-sensitive to feedstock, all types of coals or coal wastes can be used.
- The waste generated is a dry, benign solid that can be disposed of easily or usefully employed (e.g., as material for road or building construction).

What Repowering Potential Does PFBC have For Targeted Plants?

Since type or size of boiler can be repowered by PFBC technology using the existing plant area, coal and waste handling equipment, and steam turbine equipment, the life of the targeted plant can be extended. Although the initial cost may be somewhat high, there are no net incremental operating costs; unlike a scrubber, PFBC efficiency is not degraded by parasitic losses. Also, the addition of the gas turbine provides an increase in plant capacity of about 40 percent.

Pressurized Fluidized Bed Combustion Combined Cycle

ELECTRIC POWER PLANT


NOx
SO2
Hi-S
Limestone
Coal & Limestone Handling
Solid Waste
Disposal
Cyclone
PFB Boiler
Hot Clean Gas
Air
Comp.
Gas Turbine
Generator
ELECTRIC POWER
Steam
Steam Turbine
Generator
ELECTRIC POWER

SO$_2$	NOx	COMPARED WITH CONVENTIONAL TECHNOLOGY*				
EMISSION REDUCTION		PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
90–95%	Moderate	Slight Increase	40-50% INCREASE	Moderate Extension	4–6 MILLS/KWH	$800–1,000 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

Atmospheric Fluidized Bed Combustion

How Does It Work?

A fluidized bed combustor is a furnace in which a bed of solid particles is suspended in a stream of up-flowing air. The suspended particles behave like a fluid. During combustion, tubes with flowing water that are located within the bed and/or above the bed in the flue gas path are heated to form steam. The steam generated is then sent to a steam turbine for the generation of electricity. The distinctive aspect of a fluidized bed combustor is that when coal and a sorbent--such as limestone--are injected into the bed, sulfur dioxide is absorbed by the sorbent to produce a dry and benign solid. Atmospheric Fluidized Bed Combustion (AFBC) operates at or near atmospheric pressure.

What Are Its Attributes?

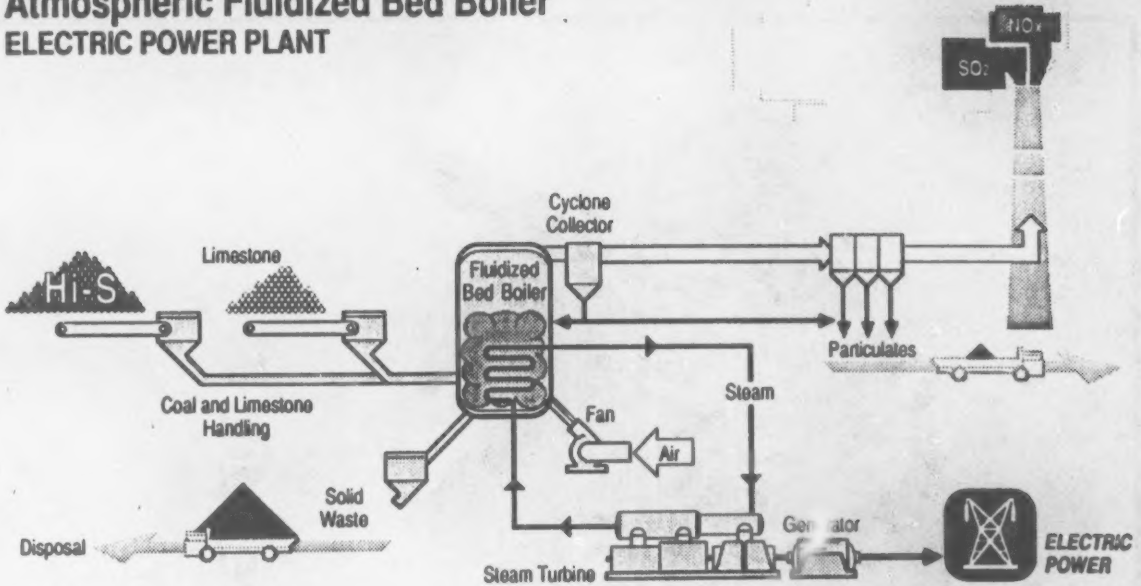
- There are no special coal handling requirements other than the addition of limestone to the coal feed.
- The flue gases require only particulate removal.
- The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the capture of sulfur dioxide.
- The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures, thus reducing formation of nitrogen oxides.
- Combustion occurs at temperatures below the ash melting point so that solids accumulation and boiler tube erosion and corrosion are minimized.
- Since it is relatively non-sensitive to feedstock, all types of coals or coal wastes can be used.
- The waste generated is a dry, benign solid that can be disposed of easily or usefully employed (e.g., as material for road or building construction).

What Repowering Potential Does AFBC Have For Targeted Plants?

An example of AFBC utility repowering is the Northern States Power project at its Black Dog Station. The existing 85 MW pulverized coal boiler was upgraded to 125 MW with a bubbling bed design AFBC boiler. It began operation in the fall of 1986. This project has resulted in a considerable reduction of SO_2 and NO_x emissions and has realized an extremely favorable economic advantage.

Since any type or size of boiler can be repowered by AFBC using the existing plant area, coal and waste handling equipment, and steam turbine equipment, the life of the plant can be extended. Although the initial cost may be high, there are no net incremental operating costs; unlike a scrubber, AFBC efficiency is not degraded by parasitic losses. In many cases (e.g., where the capacity of the boiler has been reduced because of aging, or the turbine generator has greater capacity than the boiler, or both), AFBC can be used to repower an existing boiler and, in addition to controlling SO_2 and NO_x emissions, can increase the boiler's capacity. The cost of controls is significantly reduced because of the value of the increased capacity.

Atmospheric Fluidized Bed Boiler
ELECTRIC POWER PLANT


SO2
NOx
Cyclone Collector
Limestone
Hi-S
Fluidized Bed Boiler
Particulates
Coal and Limestone Handling
Steam
Fan
Air
Solid Waste
Disposal
Generator
Steam Turbine
ELECTRIC POWER

*COMPARED WITH CONVENTIONAL TECHNOLOGY**

SO_2 EMISSION REDUCTION	NOx EMISSION REDUCTION	PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
85–90%	Moderate	No Change	10-15% INCREASE	Moderate Extension	6–8 MILLS/KWH	$700–900 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

AMERICA'S CLEAN COAL COMMITMENT

Appendix B

U.S. DEPARTMENT OF ENERGY FEBRUARY 1987

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PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS

INTRODUCTION

Each line item of Table 1, PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS, is detailed in this Appendix.

FEDERAL CONTROL TECHNOLOGY R&D

The first line item, DOE Control Technology R&D, is summarized in Table 2. It is broken down into seven categories, each of which is detailed with a narrative and a corresponding dollar table. The seven categories are:

- Control Technology and Coal Preparation R&D
- Advanced Research and Technology Development
- Combustion Systems R&D
- Heat Engines R&D
- Magnetohydrodynamics (MHD) R&D
- Surface Coal Gasification R&D
- Fuel Cells R&D

DOE Control Technology and Coal Preparation (CTCP) R&D (see Table 3) includes Flue Gas Cleanup, Gas Stream Cleanup, Waste Management and Coal Preparation.

- Flue Gas Cleanup addresses the removal of pollution causing contaminants from fossil fuel fired systems to meet current and projected environmental standards that could serve to limit the utilization of fossil fuels. Efforts will be focused on fundamental research for processes for the removal of NO_x, SO_x, and particulates, for retrofit and new utility and industrial applications.

- Gas Stream Cleanup includes the technology for removal of contaminants from gasifier and combustor process streams prior to utilization in advanced power conversion cycles such as gas turbines and fuel cells. Both hardware (e.g., gas turbines) and environmental protection are key concerns. Research is conducted in three major areas: (1) physical clean-up for coal based gas streams; (2) chemical clean-up for coal based gas streams; and (3) control of alkali and trace chemicals.

- Waste Management focuses primarily on waste sampling and characterization of emerging technology wastes to identify potential problems and develop solutions.

- Coal Preparation is directed toward the development of advanced coal cleaning technologies that will reduce the ash and sulfur content of U.S. coal so that the product can be formulated into a high quality fuel that could replace oil and/or gas and reduce environmental emissions of suspected acid rain precursors from coal-fired powerplants in both new and retrofit applications. Research is conducted in three broad areas: (1) physical treatment and cleaning; (2) chemical/biological pretreatment and cleaning; and (3) engineering support and ancillary operations.

DOE Advanced Research and Technology Development (AR&TD) (see Table 3) includes mission oriented fundamental research to increase the understanding of the mechanisms of direct coal combustion. This includes:

- Fundamental research in coal properties, including work on physical and chemical properties of uncombusted coal based fuels, and of solid, liquid and gaseous products.

- Pulverized coal combustion research and the International Energy Agency (IEA) coal combustion science program.

- Deposition research pertinent to slagging and fouling of boilers, fluidized bed heat exchanger tube wastage, and internal combustion environments.

- Coal beneficiation research studies of contaminant removal during the combustion process.

- Generic electrochemistry research.

DOE Combustion Systems R&D (see Table 4) programs are Atmospheric Fluidized Bed, Pressurized Fluidized Bed, Advanced Combustion Technology, Alternative Fuels Utilization, and EPA Limestone Injection Multistage Burner.

- Atmospheric Fluidized Bed Combustion (AFBC) includes experimental and analytical erosion studies, bench scale construction and operational testing of selected AFBC concepts, and advancing these concepts through proof-of-concept.

- Pressurized Fluidized Bed Combustion (PFBC) includes testing of advanced hot gas cleanup devices; evaluation of PFBC components; design alterations to improve systems' reliability, reduce costs, and enhance enviornmental performance; modeling studies to predict tube erosion/corrosion; research on PFBC dynamics, systems analysis and combustion characterizations; and technology and economic analyses and development of advanced PFBC systems for repowering and grass roots facilities.

- Advanced Combustion Technology includes development of the most promising systems for retrofit to oil-, gas- or coal-fired light industrial, commercial/institutional, residential, and utility applications; and testing of sorbent injection for SO_2 control.

- Alternative Fuels Utilization includes transport, handling and storage studies and emissions characterization of coal-water mixtures; and tests of ultra fine beneficiated coal-water mixtures.

- Limestone Injection Multistage Burner (LIMB) includes funding to be transferred to EPA in Fiscal Year 1988 to continue commercial-scale demonstration on a tangentially-fired utility boiler (see Table 10).

DOE Heat Engines R&D (see Table 5) programs are Gas Turbines and Diesel Engines. The principal goal is to establish technical data that will enable development of technology needed for direct firing of coal or coal-derived gaseous fuels in turbines or diesels. The programs focus on technical problems associated with substituting coal or coal-derived gaseous fuels for distillate fuels or natural gas in turbine and diesel power conversion systems. Applications of this technology include industrial cogeneration; combined cycle electric power generation, including repowering of existing generating capacity; and both rail and marine transportation.

DOE Magnetohydrodynamics (MHD) R&D (see Table 5) program provides for basic supporting research; development of components and subsystems; and the integrated, long-duration, proof-of-concept testing of the MHD topping and bottoming cycles. The next step after the integrated proof-of-concept testing is likely to be an MHD retrofit to an existing utility boiler to prove the potential efficiency and environmental advantages of MHD systems over conventional coal-fired utility systems.

DOE Surface Coal Gasification R&D (see Table 5) program fosters the development of advanced gasifier systems for the production of electric power, synthesis gas (for synthetic natural gas, indirect liquefaction, and feedstocks), industrial fuel gas, and coproducts (simultaneous production of solids, liquids, and gases). The program provides for basic and fundamental research related to Surface Coal Gasification processes, including studies of reaction mechanisms and chemistry. The program also supports the continued management and modeling of the Great Plains Project.

DOE Fuel Cells R&D (see Table 5) program is aimed at development of phosphoric acid systems, molten carbonate systems, and advanced concepts for improving the costs, efficiencies, and environmental performance of utility, industrial, and commercial energy production systems. Phosphoric acid systems have reached a near-commercial status with large scale testing underway. Molten carbonate advanced concepts systems development, scaleup, and material and component development are being supported.

EPA SO_x and NO_x Control R&D (See Table 6)

- SO_x control R&D includes Spray Drying, Direct Injection, and E-SO_x projects. Spray Drying project involves testing to provide systematic evaluation of the particulate control to assist utilities in assessing spray dry flue gas desulfurization systems. Direct Injection project involves tests of a dry sorbent injection process as a more cost-effective alternative SO_2 control compared to flue gas desulfurization systems for application to existing and new plants. E-SO_x project is aimed at modifying existing Electrostatic Precipitators (ESP) to increase capacity and ability to control SO_x.
- NO_x Control R&D includes Low NO_x combustors and reburning projects. Both of these projects involve combustion processes staged to minimize production of NO_x.

- Other Supporting Control Technology R&D includes support of EPA's Limestone Injection Multistage Burner (LIMB) and Low NO_x Burners demonstrations.

FEDERAL DEMONSTRATIONS

DOE Clean Coal Technology Programs (See Table 7)

The U.S. Department of Energy's Clean Coal Technology program is divided into three distinct pieces:

- Clean Coal Technology Program - 1 is a $396 million, Federal funds, and $599 million, State and industrial funds, program that was open to demonstration of advanced technologies that utilized the entire U.S. coal resource base and which apply to any or all of the U.S. energy marketplace (i.e., utility, industrial, commercial, residential and transportation sectors). In July 1986, nine projects were selected (see Table 8) for negotiations of cooperative agreements. The nine projects represented a variety of technologies for a variety of market applications.

- Clean Coal Technology Program - 2 In the President's Fiscal Year 1988 budget request to the Congress, $150 million were requested over a two year period (FY 1988 and FY 1989) for demonstrating projects that employ emerging clean coal technologies capable of retrofitting, repowering, or modernizing existing facilities and targeted to the recommendations of the Special Envoys. It is expected that a solicitation will be issued in Fiscal Year 1988 for this program. A minimum of 50 percent private sector cost sharing will be required for any project selected.

- Clean Coal Technology Program - 3 In the President's Fiscal Year 1988 budget request to the Congress, $200 million were also requested over a three year period (FY 1990, 1991, and 1992) for demonstrating projects that employ emerging clean coal technologies capable of retrofitting, repowering, or modernizing existing facilities (consistent with the Special Envoys' recommendations) with a primary objective of reducing SO_2 and/or NO_x emissions. It, too, will require a minimum of 50 percent private sector cost sharing for each project selected. It is anticipated that this solicitation will be issued in Fiscal Year 1990.

Other DOE Supported Projects (See Table 9)

- Commonwealth Edison, Flue Gas Desulfurization System. A regenerable flue gas desulfurization system is under construction by UOP, Inc. of Des Plaines, Illinois, for Commonwealth Edison's powerplant located at Kincaid, Illinois. This is a cost-shared construction and testing project financed by DOE ($6.2 million), the State of Illinois ($1 million), and UOP, Inc. ($312,000). Under the four-year, $7.6 million project, UOP will test a technique developed by DOE, known as the "Fluidized-bed copper oxide process," to absorb sulfur dioxide from flue gases released by burning coal. The UOP tests, being conducted under actual operating conditions, are on a large enough scale to prove the concept's technical feasibility and are scheduled for completion in 1989.

- Allis Chalmers, Kilngas Coal Gasification Plant. The Kilngas process is being demonstrated in a 600-ton per day, full-scale demonstration plant at Illinois Power Company's Wood River Station located at East Alton, Illinois. One of the goals is to demonstrate use of low-Btu gas in an existing boiler. The gasification process, developed by Allis-Chalmers, uses a specially designed rotary kiln technology to convert high-sulfur coal into a clean synthetic gas for production of electric power. At this plant, the clean-coal-derived gas is piped to the No. 3 boiler at the station, which is rated at 50 MW. The program is sponsored by the Illinois Coal Demonstration Fund and is being backed by 16 investor-owned electric utilities, the U.S. DOE, Allis-Chalmers, and the Electric Power Research Institute. This coal gasification technology is applicable to both retrofit and new generating capacity. The funding shown in Table 9 does not include more than $157 million spent by the industrial sponsors before Fiscal Year 1986.

Environmental Protection Agency (EPA) Projects (See Table 10)

This program is the Limestone Injection Multistage Burner (LIMB) demonstration on a tangentially-fired boiler. EPA is in the process of selecting a contractor for this program. In addition to the funds shown in Table 10 for this program, DOE will provide EPA with $7 million in Fiscal Year 1988.

The Babcock and Wilcox Company is the prime contractor for LIMB tests on a wall-fired boiler with an existing 105 MW coal-fired unit at Ohio Edison's Edgewater Plant located at Lorain, Ohio. Funds for that project are not included in Table 10. The cosponsors are EPA, State of Ohio, Ohio Edison Company, and the Babcock and Wilcox Company. Construction began in 1986 with completion scheduled for early 1987.

Department of the Treasury Projects (See Table 10)

- Dow Syngas Demonstration Plant. The Dow gasification process will be commercially demonstrated at the Dow Syngas plant in Plaquemine, Louisiana. It will be the world's largest (155 MW) integrated gasification, combined cycle (IGCC) plant to date, and the first to test phased-in-construction. The process will use Dow's proprietary gasfication technology to convert western subbituminous coal into medium-Btu synthetic gas. The gas will be used to fuel existing Westinghouse combined cycle gas turbines for cogeneration of electricity and steam at Dow's Louisiana Division. Engineering on the plant's major systems is complete, construction is more than half finished and startup is scheduled for early 1987. Dow Chemical Company is the sole sponsor of the project with a price guarantee commitment by the U.S. Department of the Treasury.

- Cool Water Coal Gasification Demonstration Plant. This is the first commercial scale integrated gasification, combined cycle (IGCC) powerplant in the U.S. The 100 MW (net) plant has been built at Southern California Edison's Cool Water station, near Daggett, California. The plant utilizes a Texaco gasifier to convert coal to clean fuel gas for a General Electric combined cycle unit. The IGCC technology offers several attractive features to utilities: lower SO_2/NO_x emissions; less solid wastes; less water and land use; potentially higher efficiency; as well as short construction time, phased/modular additions; and fuel flexibility. Sponsors include the Electric Power Research Insitute, Texaco, Inc., Bechtel Power Corporation, the General Electric Company, a Japanese consortium, and Southern California Edison, with a price guarantee by the U.S. Department of the Treasury. Project duration is through mid-1989.

Tennessee Valley Authority (TVA) Projects (See Table 11)

- TVA 160 MW AFBC Demonstration Plant. The TVA is constructing a new 160 MW Atmospheric Fluidized Bed Combustor (AFBC) boiler at TVA's Shawnee Steam Plant near Paducah, Kentucky. The boiler will be a bubbling-bed type with underbed feed. It will utilize the existing steam turbine and the balance-of-plant of Unit No. 10, burning high-sulfur bituminious coal. Following startup in 1988, a four-year test program is planned. Pilot-plant results indicate that more than 90 percent SO_2 retention, and significant NO_x reductions are possible. The program is sponsored by TVA, the Electric Power Research Institute, the State of Kentucky, Duke Power Company, Combustion Engineering, Inc., and the U.S. DOE. The conceptual design of the new boiler is complete, and construction is underway.

- TVA 20 MW AFBC Pilot Plant. The 20 MW Atmospheric Fluidized Bed Combustor TVA plant, located at TVA's Shawnee Steam Plant near Paducah, Kentucky, operates at a simulated utility load environment that generates steam at modern utility conditions. The objectives of the intermediate-size plant include demonstration of long-term operation with acceptable performance and compliance with environmental control regulations. Design correlations are being developed using alternate fuels and sorbents. Performance characteristics have indicated positive effects of scaling up to the demonstration size (10-fold increase). Success of this pilot plant gave TVA the confidence to begin design of a 160 MW unit (see "DOE Other Demonstrations", Table 9). Only those funds for the continued operation of this facility from Fiscal Year 1986 onward are included in Table 11; the more than $100 million previously spent on this project are not included.

- High-Sulfur Spray Dryer/Electrostatic Precipitator (ESP) Pilot Plant. The purpose of this project is to demonstrate the performance and commercial feasibility of a spray dryer/ESP SO_2 control system for retrofit applications on high-sulfur coal-fired utility boilers. EPRI and TVA are cosponsoring a three-year operation and testing program that will emphasize the effects of the spray dryer on the ESP particulate collection efficiency. Retrofitting a spray dryer to an existing ESP is expected to achieve 70 percent or greater SO_2 removal at a moderate capital cost. The project started in early 1986 and will be completed in early 1989.

STATE-FINANCED CLEAN COAL PROGRAMS (See Table 12)

Two states, Illinois and Ohio, have allocated large sums of money to their Clean Coal Technology Programs. It is known that other states, such as California, Kentucky, New York, and Pennsylvania have begun similar programs, but, since the details on the individual projects are not known, they are not included here.

- Illinois. The Illinois Coal Bond Fund, administered by the Illinois Department of Energy and Natural Resources, grants loans for the State's clean coal utilization programs. As of the end of 1986, $72 million were spent in grants and loans, with $118 million additional planned during the next five years (i.e., total of $190 million). $115 million, which is considered to be conservative, have been committed by private industry. Five million dollars, which the State of Illinois plans to contribute for cost-sharing to the DOE Clean Coal Technology-1 program, are not included in the funding levels shown in Table 12. Projects being funded include: a wet flue gas desulfurization system, using a patented liquid-gas-contacting device to absorb sulfur dioxide, is being built at the University of Illinois Champaign, Illinois; the Wormser Grate fluidized bed combustor technology will be demonstrated at Anderson, Clayton and Company's food processing plant at Jacksonville, Illinois; and a circulating fluidized bed boiler located in Decatur, Illinois, will demonstrate five large boilers to produce 108 MW for the Archer-Daniels-Midland Company.

- Ohio. Ohio's Office of Coal Development administers Ohio's Clean Coal Program. As of late 1986, $100 million have been allocated to the program, with $41.6 million committed to projects. $9 million (which is conservative) have been committed by private industry to clean coal projects other than the four Ohio-based projects sponsored by the U.S. DOE's Clean Coal Program-1. Thirty-two million dollars for cost-sharing to DOE's Clean Coal Technology-1 program are not included in the funding levels shown in Table 12. Projects being funded include: a planned post-combustion project at Ohio Edison's Toronto Station, Jefferson, Ohio; an industrial cogeneration project at Scio Pottery's plant in Scio, Ohio; a catalytic reduction process facility for coal flue gas is planned by Columbia Gas System Service Corporation in Columbus, Ohio; and a commercial demonstration of a rotary cascading bed boiler for the Hudepohl Brewery power house in Cincinnati, Ohio.

PRIVATE DEMONSTRATIONS

EPRI Privately Financed Projects (See Table 13)

Northern States Power AFBC Conversion. The project is a fluidized-bed retrofit and upgrade. (Of the $70 million shown in Table 13, $13 million are for upgrading the turbine.) Activities include: converting a pulverized coal unit to a FBC bubbling bed boiler firing subbituminous coal, and increasing the present capacity of the unit from 85 MW to 125 MW by upgrading the steam turbine. The operating life of the unit will be extended by 25 years. Following an initial operation period, a three-year test program will be initiated to monitor performance and operating characteristics. Projected emissions reduction: SO_2 up to 90 percent; NO_x, moderate reduction. Participants are Northern States Power Company and EPRI. Construction completed: 1986. Project duration is to 1989.

Colorado-Ute Circulating AFBC Demonstration Plant. The first utility-scale circulating fluidized bed steam generator in the United States is being installed at the 25-year old Nucla generating plant. This effort is part of a major project for upgrading plant output and life extension. Expected results include an increase of plant capacity from 36 MW to 110 MW, improved station heat rate by 15 percent, reduction in fuel cost by 30 percent, and reduced emissions of SO_2 (up to 90 percent) and NO_x (moderately). Participants include: Colorado-Ute Electric Association, Pyropower, Stearns Catalytic World Corporation, Peabody Coal Corporation, Westinghouse Electric Corporation, EPRI, and National Rural Electric Cooperative Association. Startup: 1987. Project duration to 1989.

Coal Cleaning Test Facility. The objectives of the Coal Cleaning Test Facility (CCTF) are to characterize the cleanability of nationally important steam coals, to develop knowledge of steam-coal quality and its importance to electric power generation, to enhance the scientific understanding of existing coal-cleaning technology, to accelerate the use of new and improved coal-cleaning technology, and to design a model to enable engineers to extrapolate better the cleanability at specific coals from laboratory scale tests. Physical coal cleaning provides for many coals a low-cost approach to reducing sulfur emissions up to 40 percent, and with advanced coal-cleaning devices, up to 65 percent. The CCTF is expected to continue R&D into the early 1990's.

High Sulfur Test Center. This is a Flue Gas Desulfurization (FGD) test facility for high-sulfur coal emission control technology research on high-sulfur coals. It will focus on technology for acidic deposition precursor control, primarily SO_2 reduction. Research will address existing FGD units, new plants and potential retrofit scrubbers. Work at HSTC should improve SO_2 removal efficiency, by-product quality, energy requirements, and water requirements for FGD. Startup in late 1986, with project duration to 1996.

Shell Oil Coal Gasification Demonstration Plant. This prototype unit is the first U.S. plant to use the Shell Coal Gasification Process. Design, engineering, operating, and environmental data necessary to build large commercial facilities will be provided by this demonstration plant. The facility's gasifier is designed to process a broad range of coals, including about 250 tons per day of high-sulfur bituminous coal or about 400 tons per day of lignite. The medium-Btu gas and steam will be consumed within Shell's adjacent manufacturing complex. The principal advantages of the Shell process are: complete conversion of a wide variety of coals, including high-sulfur coal; low ranked coals; lignite and coal fines; high thermal efficiency; efficient heat recovery through production of high pressure, superheated steam; high throughput; clean gas production without by-products; and superior environmental performance. The technology is well suited for the repowering of existing coal-fired powerplants with integrated-gasification-combined-cycle facilities. Coal gasification systems can reduce SO_2 emissions by over 99 percent and moderately reduce NO_x emissions compared to conventional coal-based systems. Participants include: Shell Oil Company; EPRI; and Lummus Crest, a subsidiary of Combustion Engineering. Production is expected to start in the first half of 1987.

Privately Financed Commercial Demonstration Projects (See Table 14)

- North Jersey Energy Associates plans to build a 140 MW cogeneration plant that will produce and burn coal-derived gas. The plant, to be located in Sayerville, New Jersey, will include a testing laboratory with 6 to 12 Wellan-Galusha gasifiers. Steam will be used in the cold storage facility and for heat in a new, nearby the plant. Construction is to begin early 1988 and startup is slated for the end of 1989. This plant will be an early commercial demonstration of cogeneration involving a coal gasification combined cycle unit in an industrial application.

- Synfuel Genesis International (SGI) and the Dravo Corporation are building a 37 MW coal-fired cogeneration plant in Colstrip, Montana, at a cost of more than $50 million. The plant is expected to be in operation in late 1989. The company's process uses selective pyrolysis to produce process coal (char) and coal liquids. The char is burned in a fluidized-bed boiler to produce electricity to be sold to the Montana Power Company. The coal-liquids by-product will be used in a variety of commercial applications. SGI expects the system to achieve up to 95 percent sulphur dioxide removal. A primary purpose of the plant is to demonstrate that the char is a suitable alternative fuel and a better product for combusting to produce steam. SCI's Colstrip facility is the prototype for the company's planned 12 new coal-fired projects slated to bring over 1,000 MW of electricity on line by 1991.

- Wisconsin Electric Power Company will retrofit four existing coal-fired units at its Oak Creek, Wisconsin, generating plant with Atmospheric Fluidized Bed Combustors (AFBC). With 500 MW capacity, this will be the world's largest AFBC power station. The first two conversions will be finished by mid-1990. This will be a commercial demonstration of a large repowering project that will reduce SO_2 emissions.

- Texas-New Mexico Power Company announced plans in early 1986 to build four 150 MW Circulating Fluidized Bed boilers that will burn lignite. Construction for the first unit is planned for mid-1987, to be brought on line in mid-1990. (The $200 million shown in Table 14 is the cost for the first unit only.) A site has not yet been chosen, but it is expected to be built in Robertson County, Texas, near massive lignite reserves. This will be a commercial demonstration of an utility-scale circulating bed AFBC.

- General Motors Corporation, in 1986, installed a 27 MW Circulating Fluidized Bed Combustor (CFBC) cogeneration unit at its assembly plant in Pontiac, Michigan, to replace two 40-year old stoker-fired boilers that cannot meet stringent state emission standards. The unit will also produce 200,000 pounds-per-hour (pph) of steam. Pyropower designed the unit. A 12-module baghouse will remove particulates from the exhaust gases. The boiler will be fired by 200 tons per hour of coal. This will be a commercial demonstration of a large industrial circulating Atmospheric Fluidized Bed repowering project that will reduce SO_2 and NO_x emissions.

- The Gilberton Power Company partnership, with Bechtel, Pyropower Corporation and Ri-Corporation Development, Inc., will build, own and operate a $130 million 79.5 MW CFBC cogeneration plant, using anthracite culm, in West Mahanoy Township, Schuylkill County, Pennsylvania. The culm will be fed into two Pyroflow boilers, each of which can produce 235,000 pph of steam. The steam will turn a General Electric turbine to produce electricity, which will be purchased by Pennsylvania Power and Light Company. The steam will be sold to a coal-drying facility that Bechtel will also build. Construction began in early 1986.

- Combustion Engineering and Lurgi Corporation are currently constructing a $38 million, 25 MW CFBC cogeneration project with the Reading Company in Reading, Pennsylvania. This is an early commercial demonstration of a cogeneration CFBC unit.

- Air Products and Chemicals, Inc., in late 1986, began construction, in Stockton, California, of a 49 MW cogeneration facility that will burn coal in a CFBC. The $100 million facility will supply CPC International's corn wet-milling plant with steam and electricity. The balance of power will be sold to Pacific Gas and Electric Company. Completion of the facility is scheduled for mid-1988. This will be a commercial demonstration of an industrial cogeneration circulating AFB project complying with California's stringent emission control requirements.

- Applied Energy Services, Inc. is building a 180 MW coal-fired cogeneration plant on the Thames River in Montville, Connecticut, at a cost of $250 million, which is scheduled to begin operating in 1989. The plant will use two circulating fluidized bed boilers and a steam turbine generator. The electricity will be sold to the Connecticut Light & Power Company and the 60,000 pounds per hour of steam will be sold to a nearby recycle paper-board plant owned by a subsidiary of Stone Container Corporation.

PRIVATE RESEARCH AND DEVELOPMENT (See Table 15)

Electric Power Research Institute (EPRI)

- Environmental Control Technology. This includes research on SO_x, NO_x, and particulate control equipment and techniques. Research on SO_x and particulate control includes furnace limestone injection, furnace calcium injection, and dry-sorbent injection. Research on NO_x control includes low-NO_x furnace design for retrofit application.

- Advanced Fossil Power Plants. This includes research on AFB, PFB, advanced combustion turbines, and gasification powerplants in support of EPRI's ongoing demonstration program. EPRI's demonstration program is funded in this category, which includes support of demonstration projects being sponsored by the U.S. DOE (TVA 160 KW plant), U.S. Department of the Treasury (Cool Water plant), and the Tennessee Valley Authority (TVA 20 MW plant and Spray Dryer Electrostatic Precipitator), Northern States Power 125 MW plant, Colorado-Ute 110 MW plant, and Shell Oil Coal Gasification plant.

- Coal Cleaning. This includes research on physical and chemical coal cleaning and advanced coal cleaning technologies.

Gas Research Institute R&D.

This includes research and development of advanced gasification programs capable of handling a wide range of coals and of downstream processes to ensure removal of contaminants from coal gases. Projects include low temperature acid gas removal, fluidized bed gasification, advanced downstream gas processing, and gasification of lignite and other coals.

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TABLE 1
PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
($ in millions)

CATEGORY		FEDERAL	STATE	EPRI	PRIVATE	TOTAL	FY	REMARKS
Federal	**Federal Control Tech. R&D**							
	DOE	738				738	86-92	Budget Projections
	EPA	21			7	28	86-92	Budget Projections
	Subtotal	759			7	766		
	Federal Demonstrations							
	DOE Clean Coal Prog-1	396	39		560	995	86-88	9 Projects in negotiations
	DOE Clean Coal Prog-2	150			150	300	88-89	Estimated as 50% co-funding
	DOE Clean Coal Prog-3	200			200	400	90-92	Estimated as 50% co funding.
	Other DOE Supported Project	14	4		1	19	91-92	Commonwealth Ed. & Kilngas
	Environmental Protection Agency Projects	5			12	17	86-92	Tangentially fired LIMB
	Dept. of Treasury Projects	480 *	2	105	600	1187	86-92	DOW Syngas & Cool Water * Represents price guarantees to be paid out
	Tennessee Valley Authority Projects	67	10	81	82	240	86-92	160 MW AFBC, 20 MW AFBC & Spray Dryer/ESP
	Subtotal	1312	55	186	1605	3158		
	Federal Total	2071	55	186	1612	3924		
Nonfederal	**State-Financed Clean Coal Programs** **Subtotal**		253		174 **	377	86-92	Illinois and Ohio Only ** Co-funding not fully determined
	Private Demonstrations							
	EPRI Privately Financed Projects			79	287	366	86-89	5 Projects
	Other Privately Financed Projects				1338	1338	86-92	
	Subtotal			79	1625	1704		
	Private Research & Development							
	EPRI R&D			103		103	86-89	
	GRI R&D				40	40	86-89	
	Subtotal			103	40	143		
	Nonfederal Total		253	182	1789	2224		
Summary	**Total U.S.**	2071	308	368	3401	6148		

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TABLE 2

PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATION
DOE CONTROL TECHNOLOGY R&D
($ in millions)

	FY 1986	FY 1987	FY 1988	FY 1989	FY 1990	FY 1991	FY 1992	TOTAL
ntrol Technology and Coal Preparation R&D								
Flue Gas Cleanup	11	13	13	14	15	15	15	96
Gas Stream Cleanup	7	13	7	7	8	8	8	58
Waste Management	1	1	1	2	1	2	2	10
Coal Preparation	13	11	12	12	13	13	13	87
Subtotal	32	38	33	35	37	38	38	25
Advanced Research and Technology Development								
Direct Utilization	11	11	9	10	10	10	10	71
	11	11	9	10	10	10	10	71
Combustion Systems R&D								
AFB Combustion	2	3	2	1	1	2	2	14
PFB Combustion	5	6	7	8	8	8	8	50
Advanced Combustion Technology	3	3	2	3	3	3	3	20
Alternative Fuels Utilization	4	3	4	4	4	4	4	27
Limestone Injection Multistage Burner	0	0	7	0	0	0	0	7
Subtotal	14	15	22	16	16	17	17	118
eat Engines R&D	12	12	8	9	9	10	10	71
Magnetohydrodynamics (MHD) R&D	28	26	0	0	0	0	0	54
Surface Coal Gasification	27	24	6	6	6	7	7	83
Fuel Cells R&D	34	28	5	6	6	6	6	91
Total DOE Control Technology R&D	158	155	83	82	85	87	88	738

NOTE: Totals may not be exact due to rounding

TABLE 3

21-Jan-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(Continued)

	FY 86-92	($ in Millions)		Other	Total
FEDERAL CONTROL TECHNOLOGY R&D (note 2)	Federal	State	EPRI	Private	(note 1)
DOE Control Technology and Coal Preparation (CTCP) R&D					
o Flue Gas Cleanup	96				96
o Gas Stream Cleanup	58				58
o Waste Management	10				10
o Coal Preparation	87				87
	----				----
Subtotal	251				251
DOE Advanced Research and Technology Development (AR&TD) Direct Utilization, including:					
o Fundamental research in coal properties	71				71
o Pulverized coal combustion research					
o Deposition research on boilers and heat exchangers					
o Coal beneficiation research					
o Generic electrochemistry research					
	----				----
Subtotal	71				71

NOTE 1: Totals may not be exact due to rounding

NOTE 2: DOE Federal Control Technology R&D includes DOE funding only, even though many of the programs are cost-shared.

TABLE 4

05-Feb-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(Continued)

FEDERAL CONTROL TECHNOLOGY R&D (Continued)	FY 86-92 Federal	($ in Millions) State	EPRI	Other Private	Total (note)
DOE Combustion Systems R&D					
o AFB Combustion	14				14
o PFB Combustion	50				50
o Advanced Combustion Technology	20				20
o Alternative Fuels Utilization	26				26
o Limestone Injection Multistage Burner (note 2)	7				7
	----				----
Subtotal	118				118

Note 1: Totals may not be exact due to rounding

Note 2: Funds to be transferred to EPA in FY 1988 for management of the tangentially-fired LIMB demonstration.

TABLE 5

21-Jan-87

PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(Continued)

FEDERAL CONTROL TECHNOLOGY R&D (Continued)	FY 86-92 ($ in Millions) Federal	State	EPRI	Other Private	Total (note)
DOE Heat Engines R&D	70				7C
o Gas Turbines					
o Diesel Engines					
	----				----
Subtotal	70				70
DOE Magnetohydrodynamics (MHD) R&D	54				54
o Basic Supporting Research					
o Development of Components and Subsystems					
	----				----
Subtotal	54				54
DOE Surface Coal Gasification R&D	83				83
o Development of Advanced Gasifier Systems					
o Basic Research of Gasification Processes					
	----				----
Subtotal	83				83
DOE Fuel Cells R&D	91				91
o Phosphoric Acid Systems					
o Molten Carbonate Systems					
o Advanced Concepts					
	----				----
Subtotal	91				91
TOTAL DOE Control Technology R&D	738				738

NOTE: Totals may not be exact due to rounding

TABLE 6

21-Jan-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(Continued)

FEDERAL CONTROL TECHNOLOGY R&D (Continued)	FY 86-92 ($ in Millions) Federal	State	EPRI	Other Private	Total (note)
EPA SOx and NOx Control R&D					
o SOx Control R&D	3			5	8
o NOx Control R&D	3			2	5
o Other Supporting Control Technology R&D	15			0	15
	----			----	----
TOTAL EPA Control Technology R&D	21			7	28
Subtotal Federal Control Technology R&D	759			7	766

NOTE: Totals may not be exact due to rounding

TABLE 7

29-Jan-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS (CONTINUED)

	FY 86-92	($ in Millions)		Other	
FEDERAL CONTROL TECHNOLOGY R&D (Continued)	Federal	State	EPRI	Private	Total
FEDERAL DEMONSTRATIONS					
DOE Clean Coal Program - 1	396	39		560	995
o 9 Projects Selected (See accompanying table)					
o Cooperative Agreements Being Negotiated					
o Projects Meet Many of Lewis/Davis Criteria					
DOE Clean Coal Program - 2	150	Unknown		150 (note)	300
o Funding Requested					
o Solicitation for Retrofit, Repower, and Modernize to be issued in FY 88					
DOE Clean Coal Program - 3	200	Unknown		200 (note)	400
o Funding to be Requested FY 90,91,92					
o Solicitation for Emissions Reductions to be Issued in FY90					
Subtotal	746	39		910	1695

Note: Assumes a minimum of 50% private sector cost-sharing

TABLE 8

PROJECTS SELECTED UNDER U.S. DEPARTMENT OF ENERGY CLEAN COAL TECHNOLOGY PROGRAM-I

Project	Technology	Location
American Electric Power	PFB Combustion Combined Cycle	Brilliant, Ohio
Babcock & Wilcox	LIMB/Sorbent Injection	Lorain, Ohio
Coal Tech Corp.	Advanced Combustor with Sorbent Injection	Williamsport, Pennsylvania
Energy and Environmental Research Corp.	Gas Reburn/Sorbent Injection	Springfield/Hennepin/ Bartonville, Illinois
Energy International, Inc.	In-Situ Gasification	Rawlins, Wyoming
General Electric Co.	Integrated Gasification Combined Cycle	Evandale, Ohio and Dunkirk, New York
Ohio Ontario Fuels, Inc.	Coal-Oil Coprocessing	Warren, Ohio
The M. W. Kellogg Co.	Integrated Gasification Combined Cycle	Cairnbrook, Pennsylvania
Weirton Steel Corp.	Direct Iron Ore Reduction	Weirton, West Virginia

TABLE 9

11-Feb-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(CONTINUED)

FEDERAL CONTROL TECHNOLOGY R&D (Continued) FEDERAL DEMONSTRATIONS (Continued)	FY 86-92 Federal	($ in Millions) State	EPRI	Other Private	Total
Other DOE Supported Projects					
o Commonwealth Edison, Copper Oxide Regenerable Flue Gas Desulfurization System (note 1)		1			1
o Allis Chalmers, Kilngas Coal Gasification Project (note 2)	14	3		1	18
	----	----		----	----
Subtotal	14	4		1	19

Note 1: DOE funds of $6.2 million are included in the DOE R&D flue gas cleanup category. UOP Inc. is contributing $312,000.

Note 2: The State of Illinois has invested $24 million prior to 1986. A consortium of private sponsors, including utilities, EPRI, and Allis Chalmers, contributed $157 million prior to FY 1986.

TABLE 10

11-Feb-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(CONTINUED)

FEDERAL CONTROL TECHNOLOGY R&D (Continued) FEDERAL DEMONSTRATIONS (Continued)	FY 86-92 Federal	($ in Millions) State	EPRI	Other Private	Total
Environmental Protection Agency Projects (note 1)	5			12	17
o Limestone Injection Multistage Burner (LIMB) Demonstration Plant (note 2)					
Subtotal	5			12	17
Department of the Treasury Projects (note 3)	480	2	105	600	1187
o Dow Syngas Demonstration Plant					
o Cool Water Coal Gasification Demonstration Plant					
Subtotal	480	2	105	600	1187

Note 1: Funding does not include approximately $35 million Federal, State, and private contributions to EPA's wall-fired LIMB demonstration.

Note 2: Funding does not include $7 million to be transferred from DOE to EPA in FY 1988 for management of the tangentially-fired LIMB demonstration.

Note 3: Estimate only, due to proprietary restrictions on financial information.

TABLE 11

11-Feb-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS (CONTINUED)

FEDERAL CONTROL TECHNOLOGY R&D (Continued) FEDERAL DEMONSTRATIONS (Continued)	FY 86-92 ($ in Millions) Federal	State	EPRI	Other Private	Total
Tennessee Valley Authority Projects					
o 160 MW Atmospheric Fluidized bed Combustion (AFBC) Plant (note 1)	55	10	75	82	222
o 20 MW Atmospheric Fluidized Bed Combustion (AFBC) Pilot Plant (note 2)	2		2		4
o Spray Dryer/Electrostatic Precipitator (ESP) Pollution Control Device Pilot Plant	10		4		14
Subtotal	67	10	81	82	240

Note 1: Federal Funding includes: DOE $15 million and TVA $40 million

Note 2: Funding does not include over $100 million spent on the project before FY 1986.

TABLE 12

11-Feb-87

PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(CONTINUED)

	FY 86-92 ($ in Millions)				
OTHER STATE CLEAN COAL TECHNOLOGY PROGRAMS (note 1)	Federal	State	EPRI	Other Private	Total
o Illinois (note 2)		185		115	300
o Ohio (note 3)		68		9	77
		----		----	----
Subtotal Other State CCT Programs		253		124	377

Note 1: Funding is not known for several other states with Clean Coal Technology Programs.

Note 2: Not included are $5 million that the State of Illinois plans to contribute for cost-sharing to the DOE Clean Coal Technology - Program 1.

Note 3: Not included are $32 million that the State of Ohio plans to contribute for cost-sharing to the DOE Clean Coal Technology - Program 1.

TABLE 13

EPRI PRIVATELY FINANCED PROJECTS

($ in Millions, 1986-1989)

	EPRI	OTHER*	TOTAL
Northern States Power AFBC Conversion (125 MW) (Black Dog Unit #2, Minneapolis, MN)	$ 10	$ 60	$ 70
Colorado-Ute Circulating AFBC Demonstration Plant (110 MW) (Nucla, CO)	14	100	114
Coal Cleaning Test Facility (Homer City, PA)	15	-	15
High Sulfur Test Center New York Electric Gas (Somerset Station, Niagra, NY)	32	13	45
Shell Oil Coal Gasification Demonstration Plant (Deer Park Complex, Houston, TX)	8	114	122
Total	$ 79	$287	$366

*Note: Includes State and non-EPRI funding

TABLE 14

PRIVATELY FINANCED COMMERCIAL DEMONSTRATION PROJECTS

	$ in Millions	Size	Startup
North Jersey Energy Assoc., Sayerville, NJ	150	140 MW	1989
Synfuel Genesis International, Colstrip, MT	50	37 MW	1989
Wisconsin Electric Power Co., Oak Creek, WI	380	500 MW	1990
Texas-New Mexico Power Co., Robertson County, TX	200	150 MW	1990
General Motors Corp., Pontiac, MI	40	27 MW	1986
The Gilberton Power Co., West Mahanoy, PA	130	80 MW	Construction began 1986
Combustion Engineering, Reading, PA	38	25 MW	Under construction 1986
Air Products & Chemicals, Inc., Stockton, CA	100	49 MW	1988
Applied Energy Services, Inc., Montville, CT	250	180 MW	1989
Total	1338		

TABLE 15

11-Feb-87 PLANNED CLEAN COAL TECHNOLOGY R&D AND DEMONSTRATIONS
(CONTINUED)

	FY 86-92 ($ in Millions) Federal	State	EPRI	Other Private	Total
PRIVATE RESEARCH & DEVELOPMENT					
EPRI R&D					
o Environmental Control Technology			84		84
o Advanced Fossil Power Plants (Funds in this category support EPRI's demonstration plant program)					
o Coal Cleaning			19		19
			----		----
Subtotal			103		103
GRI R&D				40	40
			----	----	----
Private R&D Subtotal			103	40	143

APPENDIX II

Additional Material Submitted for the Record

Statement of Don Etchison
Director, Illinois Department of Energy and Natural Resources
Committee on Energy and Natural Resources
U.S. Senate
S. 879, The "Clean Coal Technology Deployment Act"
May 18, 1987

Mr. Chairman, members of the Committee, my name is Don Etchison. I am the Director of the Illinois Department of Energy and Natural Resources. I appreciate this opportunity to submit testimony today on behalf of Governor Thompson and the State of Illinois in support of The "Clean Coal Technology Deployment Act" (S. 879).

Illinois is committed in word and deed to the development of technologies that burn our coal in an environmentally sound manner. We have taken an active role in basic scientific research and the demonstration of innovative clean coal technology. Illinois has invested more than any other state in coal research and development. Over $61 million in state funds have been provided on a cost-share basis to develop 11 new research and demonstration projects aimed at proving the effectiveness and reliability of advanced technologies such as fluidized bed combustion, low Btu coal gasification and new generation flue gas desulfurization. Our state-supported projects represent over $455 million in investments by private industry, utilities, research organizations, universities and the federal government. Furthermore, Governor Jim Thompson has historically supported a federal clean coal technology cost-sharing program that would provide the demonstration and commercialization basis for new control technology for new plant construction, retrofit applications and repowering.

We support a Clean Coal Technology Program that can achieve these new technologies by addressing regulatory and financial constraints that go hand-in-hand with the technological uncertainties that cause impediments to commercial deployment of innovative clean coal technology. Such a program of financial incentives and regulatory adjustments will ensure the application of new technologies far beyond the projects that could be funded under a short term demonstration program. S. 879 sets up such a program to achieve these criteria. Furthermore, the bill serves as an excellent continuum to the Clean Coal Technology Programs now underway at the federal and state level.

Advantages of a National Clean Coal Deployment Program

Government-Industrial cooperation has proven to be an effective approach in the development of innovative technology. In Illinois, we have benefitted greatly from this type of coordinated effort (see Appendix). We feel stronglythat clean coal technology deployment applied on a national scale will be as successful as Illinois' programs.

- We have the time to bring new technologies that are now emerging up to a commercially acceptable level of deployment.

- A national deployment program will be a good investment as at least half of the dollars are provided by private sources and will be given a strong risk assessment by utilities. Furthermore, the future commercial use of successfully demonstrating technologies promise to result in much lower levels of pollutant causing emissions.

Construction and Repowering of New Plants. The current generation of clean coal technologies developed over the past 20 years have increased costs to power plants. Electric Power Research Institute (EPRI) estimates show an increase in a factor of three in constant dollars. Furthermore, these developments have provided only SO_2 control, while not addressing NO_x emissions.

Given the expectation of expanded energy needs in the next decade, S. 879 offers an opportunity to meet capacity with new technologies that may be more cost effective than wet flue gas desulfurization (FGD) systems. There is also promise to control not just SO_2 emissions, but NO_x emissions as well, a pollutant that cannot be controlled by wet FGD systems.

If current pollution control technology is unattractive for new power plants, it is often out of the question for repowering and retrofit applications. A good example of what may be a dilemma under future NO_x emission requirement laws is the failure of current technology to control cyclone boiler emissions, a type of boiler commonly used in Illinois. Emerging clean coal technologies hold the only promise of controlling NO_x emissions from this type of boiler.

Advantages of a ten year program. Senator Byrd's call for a ten year program would allow the most promising technologies to be tested and proven. Commercial deployment of the best technology could then take place at a time when our nation will be in need for new capacity.

The principle that guides clean coal technology development is that both emission and cost reduction must be achieved cooperatively to maintain environmental improvement. The bill would provide a natural phasing towards lower emissions at a rate that is accelerated over what is to be expected with current new source performance standards (NSPS).

Also, there is concern among certain experts that proposed acid rain legislation would lead only to research and development of emerging technology and not actual deployment. S. 879 outlines an actual commercial deployment program.

Advantages of a $3.5 billion Program. Given the ever present budgetary constraints that face Congress, there is concern that a $3.5 billion program may be an unreasonable commitment for the federal government to make over the next ten years. There are four points to consider, however, in support of this level of funding.

- The cost of Senator Byrd's Clean Coal Technology Program is minimal compared to the estimated costs of current acid rain proposals, which would total over $200 billion over the next 10 to 15 years.

- $3.5 billion is a small amount to invest compared to the major technological advancements our nation will lose to other countries in the absence of a federal program.

- The program, extended over a ten year period, would have less impact on the federal budget than Clean Coal Technology Programs proposed that call for shorter time frames.

- The ten year program makes it possible to support the application of the most promising clean coal technology to large scale retrofits, repowering and new plants in the late 1990's.

The Need for State and Federal Regulatory Incentives. A major concern that S. 879 addresses is the need for a federal policy that all state regulators must meet. In Illinois, we are committed to seeking regulatory changes at the state level that go hand-in-hand with what S. 879 would require if enacted.

Illinois, like most other states, has utility regulations that could hinder the application of deployment of clean coal technology. It is important for the federal government to address the following issues which would also give direction to individual states in their regulatory rule-making process.

- Immediate recovery of design and engineering costs related to clean coal project development.

- Recovery of costs, as incurred, for construction-work-in-progress when an approved clean coal technology is applied to an existing power plant for retrofit, repowering or modernization.

- Rapid amortization of the capital costs of approved clean coal technology projects.

- Potential for FERC to allow incentive rates of return on investments in clean coal technologies.

- Rebuttable presumption that expenditures made in a designated clean coal technology project are prudent.

- Exemption of equipment suppliers, construction firms and other potential participants in clean coal demonstration projects from the Public Utility Holding Company Act of 1935 and Parts II and III of the Federal Power ACt.

- Clean coal technology will be required to meet only the environmental standards that it is capable of achieving.

Conclusion

The successful commercial deployment of clean coal technology will assure the use of our nation's coal markets and provide added energy options to be utilized as demand increases. The second generation technologies, ones that have been tested and are actually put into operation, will fulfill these needs. A cooperative, federal and state initiative would bring this concept to fruition. Illinois is dedicated to the development of clean coal technology. We strongly urge this Committee to support S. 879 which creates a federal program designed to encourage the commercial deployment of innovative clean coal technology.

Thank you, Mr. Chairman and Committee members, for your consideration of Illinois' remarks on S. 879, the "Clean Coal Technology Deployment Act".

Appendix

Illinois Programs

The State of Illinois launched in 1974 an aggressive program to take the most promising new coal technologies from the drawing board to full commercial use. This coal demonstration and commercialization program, is administered by the Illinois Department of Energy and Natural Resources (ENR).

To date, the State's Coal Development Funds have provided more than $61 million in support of nine state-of-the-art demonstration projects. In each case, cosponsors from private industry, utilities and others have supplied the balance of the project costs that together total more than $500 million.

A description of these projects follows:

Great Lakes Naval Training Station Fluidized Bed Demonstration. This, the first Illinois clean coal technology project was awarded in 1977. Located at the Great Lakes Naval Training Station, the project demonstrated a shop-assembled atmospheric fluidized bed (AFB) boiler plant capable of supplying 50,000 pounds per hour of high pressure superheated steam using high-sulfur coal as the primary fuel. The Combustion Engineering FBC boiler supplemented six natural gas fired boilers which provide 750,000 pounds of steam per hour for heating and cooling the base and Veterans Administration hospital.

The demonstration of this fluidized bed boiler helped bring a new industrial boiler technology into the U.S. It proved that it is possible to burn high sulfur coal in a bubbling bed of limestone to reduce the emission of SO_2 into the atmosphere.

KILnGAS Low Btu Gasification Demonstration. Allis-Chalmers KILnGAS project demonstrated the conversion of Illinois high-sulfur coal to a clean low-Btu gas.

The major component of the system is the KILnGAS gasifier, a pressurized, ported rotary kiln. Air and steam are injected into the kiln through the ported shell in a controlled reaction to produce synthetic gas from coal. The low-Btu gas produced is suitable for use directly as fuel for new power generation repowering or conversion from natural gas or oil.

The KILnGAS module is capable of processing 600 tons per day of Illinois coal, producing 409 million Btu/hr. of low-Btu gas. Product gas is fired directly in an existing Illinois Power boiler, currently fueled by oil, to generate up to 40 megawatts of electricity.

The demonstration of the KILnGAS process has proven that high sulfur coal can be converted to low-Btu gas, burned in a utility generator and produce electricity. The process has demonstrated over 90% sulfur removal.

The Midwest Grain Products Company of Illinois together with Foster-Wheeler demonstrated an advanced atmospheric fluidized bed (AFB) boiler with cogeneration capability.

The company evaluated a range of technologies before selecting a combined AFB/cogeneration system as the most cost-effective alternative. This system offers a number of practical advantages for the facility, since it is designed to allow the use of Illinois coal without the addition of flue gas desulfurization equipment, and to provide low cost electricity as well as steam for use at the facility.

The technology which has been installed at the Pekin site is an innovative Foster-Wheeler AFB boiler system designed to produce process steam and generate most of the electricity needed at the facility. Flue gases from the boilers are used to replace natural gas for grain drying operations.

The successful demonstration of the project boiler proved 93.3% availability, and 82.9% efficiency. Emissions meet all new industrial source standards. The plant uses 50,000 tons of coal per year to develop process steam and cogenerate 3500 KW of electrical power. Annual energy cost savings for Midwest Grain Products is estimated to be over $2 million. This FBC system has logged more than 23,000 hours of operation in the past two years.

B.F. Goodrich Henry Plant, Circulating Fluidized Bed Demonstration. The B.F. Goodrich project demonstrated an advanced circulating fluidized bed combustion (CFBC) boiler at the company's chemical plant in Henry, Illinois.

The boiler represents a second-generation fluidized bed technology that allows the use of high sulfur coal with highly efficient pollution control. The concept of the circulating bed incorporates design features allowing quick response time, high turndown ratio, increased efficiency, and ease of operation. This was the first use of CFBC with high sulfur coal.

The 125,000 lb./hr. Pyroflow CFBC boiler developed by the Pyropower Corporation supplies all process steam requirements of the Henry facility. The successful demonstration of the project boiler proved 95% availability and 85% efficiency. Emissions meet IEPA standards. The plant uses 50,000 tons of coal per year to develop process steam. Annual energy cost savings for B.F. Goodrich is estimated to be nearly $2 million. The unit has operated for over 9,000 hours since October, 1985.

Abbott Power Plant, Advanced Scrubber Demonstration. The Abbott Power Plant Scrubber project provides for the design, construction and demonstration of an advanced flue gas desulfurization system at the University of Illinois in Champaign. The project is part of an overall coal reconversion of the Abbott facility, the largest university power plant in the U.S.

The CT-121 scrubber technology, produces a non-polluting, saleable gypsum by-product using inexpensive limestone as a reagent for SO_2 removal. Construction of the unit is now completed. The operational phase of the project will include the participation of the Electric Power Research Institute. When construction and testing of the converted boilers and scrubber is complete, the U of I expects to realize annual energy cost savings of nearly $5 million. The plant will use 100,000 tons of coal per year. The scrubber will produce a saleable gypsum by-product. SO_2 capture is designed to exceed 90%.

Anderson, Clayton & Co., Wormser Grate Dual Fluidized Bed Retrofit Coal Combustion Project. The project retrofitted one of the existing boilers by installation of the Wormser Grate Fluidized Bed Combustion System. The retrofit permits the use of Illinois high sulfur coal to replace oil and gas as the primary fuel for plant operations while meeting new source emission standards.

In the existing boiler plant built in 1953, there are two 65,000 pound per hour boilers fired with natural gas and/or fuel oil and designed to operate at a pressure of 165 psig. The installation of the Wormser retrofit FBC increases overall steam generating capacity of the old boiler and assures low SO_2 emissions (design reductions of 90% for SO_2). This system has begun operation.

Archer-Daniels-Midland Company , Large Circulating Fluidized Bed/Cogeneration Demonstration. This fluidized bed combustion project is the largest of its kind in the world. Natural gas fired boilers and purchased electricity will be displaced by five coal-fired Keeler/Dorr-Oliver circulating fluidized bed boilers. The boilers will each be capable of producing 425,000 pounds of 1300 psig, 900°F seam per hour for delivery to six turbine generators. The design incorporates a number of innovative features aimed at reducing boiler capital and operating costs and keeping maintenance at a minimum.

ADM expects to realize annual energy cost savings of about $70 million when all boilers are on-line. The plant will use nearly 1.5 million tons of coal to produce process steam and cogenerate about 100 megawatts of electricity. Emissions from the project boilers will meet industrial new source standards.

Commonwealth Edison Kinkaid Station, UOP Fluidized Bed Copper Oxide Process Proof of Concept Testing. UOP Process Division located in Des Plaines, Illinois, submitted, in response to an RFP, a proposal to the U.S. Department of Energy, Pittsburgh Energy Technology Center on "Proof of Concept Testing of the Fluidized Bed Copper Oxide Process." This proposal was selected as a basis for negotiation of a contract which was finalized in 1985. USDOE, UOP and the State of Illinois will cosponsor the work.

The copper oxide flue gas desulfurization process demonstration is expected to prove 90% simultaneous removal of both SO_2 and NO_x from an existing utility coal fired boiler. The process will produce a saleable by-product. Successful demonstration will prove the process to be economically competitive with other flue gas desulfurization systems.

Three Utility Site Gas Reburning - Sorbent Injection (GR-SI) for Sulfur Dioxide and Nitrogen Oxides Control. City, Water, Light and Power's (CWLP) Lakeside II Station, Springfield. Central Illinois Light Company's (CILCO) Edward Station, Bartonville and Illinois Power Company's (IP) Hennepin Station, Hennepin. The latest Illinois clean coal project is one of the nine clean coal technology I selections.

The Gas Reburning-Sorbent Injection (GR-SI) process involves co-firing pulverized coal and natural gas in combination with sorbent injection to reduce NO_x and SO_2 emissions by at least 50% from pre-NSPS utility boilers firing high sulfur coal. The gas burning technology and the sorbent injection technology are complementary. They have a very low capital cost and the total cost of emission control is projected to be considerably less than flue gas scrubbing.

The GR-SI process will be demonstrated on the three major types of coal fired utility boilers: a wall-fired boiler (CILCO), a tangentially or corner-fired boiler (IP), and a cyclone-fired boiler (CWLP). This variety of firing systems will provide a thorough evaluation and demonstration of the technology as a retrofit approach for emission control. the program includes design, installation, and optimization of GR-SI systems at each of the demonstration sites over the next four years. The program will be closely coupled with industry to maximize the commercialization of the technology.

The successful demonstration of the GR-SI process is expected to show that 50% removal of both SO_2 and NO_x is possible using this low capital cost retrofit technique on electric utility boilers.

jk003

Missouri Public Service Commission

Area Code 314
751-3234

P.O. BOX 360
JEFFERSON CITY
MISSOURI 65102

Commissioners:
WILLIAM D. STEINMEIER
Chairman
CHARLOTTE MUSGRAVE
ALLAN G. MUELLER
CONNIE B. HENDREN
JAMES M. FISCHER

ROBERT J. SCRIBNER
Staff Director

HARVEY G. HUBBS
Secretary

WILLIAM C. HARRELSON
General Counsel

May 18, 1987

Honorable J. Bennett Johnston, Chairman
United States Senate
Committee on Energy and Natural Resources
United States Senator
Washington, D.C. 20501

RE: Senate Bill 879, a bill proposing the Clean
Coal Technology Deployment Act

Dear Senator Johnston:

We want first to take this opportunity to express our appreciation for having been given the chance to comment on Senate Bill 879, the Clean Coal Technology Deployment Act.

On behalf of the Missouri Public Service Commission, I would like to encourage the Senate Committee on Energy and Natural Resources to provide unanimous support for this proposed legislation. Not only is the Missouri Commission interested in maintaining and improving the overall quality of the air the citizens of our State must breath, it is equally concerned that the natural beauty and integrity of Missouri's hundreds of fresh water lakes and acres of forest lands be preserved.

As with many states in the Midwest, Missouri's utilities rely heavily on coal as a primary energy source for the generation of electricity. Because of our utilities' heavy reliance on coal, it is important to our State that electrical generation be accomplished as economically and as cleanly as possible. It is the feeling of the Missouri Commission that in providing funding for the commercialization of clean coal technologies, Senator Byrd's proposed bill will help to accomplish both of these worthy objectives.

Furthermore, since ours is one of the more fortunate states to have large reserves of coal, we would naturally like to see Missouri's coal markets expanded. Unfortunately, Missouri coal generally contains significant amounts of sulfur and therefore produces substantially more pollutants during combustion than coal mined in many of our fellow coal producing states. It is the feeling of the Commission that any stimulus that can be provided at the Federal level which could result in making Missouri coal more attractive for use as a boiler fuel, is of extreme importance. Investment in the development of clean coal technology could provide a much needed economic boost to Missouri's coal industry and at the same time help the nation's industries further exploit a valuable domestic energy resource.

Although voicing support for Senator Byrd's bill, the Missouri Commission does take exception to Section 6(b) of the proposed legislation. The Missouri Commission objects to Section 6(b) on the grounds that by imposing "a rebuttable presumption that any clean coal project expenditure is prudent", the proposed legislation infringes on the prerogatives of the state regulatory agencies by attempting to preempt states' authority in the determination of just and reasonable utility rates. Notwithstanding this bill's attempt at Federal preemption, I feel confident that all prudent expenditures for the deployment of clean coal technology, in falling under normal regulatory scrutiny, will be given serious consideration by the Missouri Commission in its determination of what costs are recoverable through utility rates.

Again, on behalf of the Missouri Public Service Commission, thank you for this opportunity. We hope that you find our comments of value in your deliberations of this proposed legislation.

Sincerely,

THE MISSOURI PUBLIC SERVICE COMMISSION

William D Steinmeier

By William D. Steinmeier
Chairman

WDS/DTP/ss

cc: Committee on Energy and Natural Resources
Paul Rodgers, Administrative Director General Counsel
National Association of Regulatory Utility Commissioners

"CLEAN COAL TECHNOLOGY RESEARCH AND ACID RAIN CONTROL"

TESTIMONY TO THE UNITED STATES
SENATE COMMITTEE ON ENERGY AND
NATURAL RESOURCES

MAY 26, 1987

BY

ROBERT ABRAMS, ATTORNEY GENERAL
OF THE STATE OF NEW YORK

New York State Department of Law
The Capitol
Albany, New York 12224
(518) 474-4819

First, I wish to thank the members of the Committee for providing me with the opportunity to comment on various clean coal technology demonstration proposals presently before the Congress. I oppose these bills and appropriations unless they are tied to a timetable for reductions in acid rain emissions. Otherwise, the taxpayer's money will be poorly spent and environmental damage will continue unabated.

I am the chief legal officer of a state suffering enormous ecological, health and economic damages from acid rain. I have previously testified before the committees of Congress urging passage of comprehensive acid rain control bills. For many years I have been part of a multi-state litigation effort seeking to force EPA to use the existing Clean Air Act to regulate emissions which cause acid rain. In absence of federal action New York passed state legislation which is achieving significant cuts in our state's emissions of acid rain pollutants.

For years, the Administration and Congress have failed to address the interstate and international inequities which are at the heart of the acid rain debate. Nevertheless, although no comprehensive acid rain bill has been enacted, it is apparent that many of the obstacles which have blocked passage have been removed. The causes and effects of acid rain are well-established. In addition to the damages acid rain inflicts on our natural resources, Congress heard testimony earlier this year about how the air pollution which causes acid rain also causes significant levels of respiratory disease, particularly in children. And there is now general agreement that we can stop these damages by reducing annual emissions of sulfur dioxide by about 10 to 12 million tons and nitrogen oxides by 4 million tons. Given widespread support for acid rain controls among the public shown in recent polls[1] and in the Congress,[2] acid rain emission reductions are inevitable. The only questions remaining are how soon and how much.

Currently, the acid rain debate focuses upon proposals to spend huge sums of money for research on new air pollution control technologies which promise reductions at a lower cost than existing control methods. Many of those in favor of these expensive and time-consuming proposals have opposed passage of a comprehensive acid rain control bill.

I have strong reasons to be skeptical of these proposals. At first glance they appear to be just another delay tactic -- a variation of the "research before reduce" theme we have heard from the administration for years as an excuse for inaction. But there is a positive side to these research proposals. Implicit in them is, at long last, a recognition that there is a definite need to reduce the air pollution which causes acid rain. This is a major concession coming from elected officials and interest groups who have always refused to do so before.

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[1] A Gallop Poll in January, 1987 found that 67.7% of persons surveyed in eastern states believe that acid rain is a "very serious" or "quite serious" problem. Figures were only slightly lower for people in the midwest and southern states.

[2] In 1986, H.R. 4567 was co-sponsored by over 170 members. In 1985, a comprehensive acid rain bill was passed unanimously by the Senate Environment and Public Works Committee.

But these various proposals contain serious defects which, if uncorrected, probably will not be supported by the Congress as a whole and, even if enacted, doom the program to wastefulness and inefficiency.

My central objection to these proposals is their underlying assumption that research on clean coal technology to reduce acid rain pollutants, to be carried out over an extended period, is enough for now. This research must not become a substitute for, or a reason to delay passage of comprehensive acid rain control bill that contains mandatory emission reductions. A mandatory deadline for cutting acid rain emissions is not only compatible with a clean coal research program -- it is essential to its success.

Presumably the purpose of the clean coal research program is to develop new emission control technology at the least cost and in the shortest amount of time. The only way to achieve this goal is to link the appropriation of funds for this research to a nationwide program mandating large reductions in emissions of sulfur and nitrogen oxides. Without this prerequisite, the clean coal research program will not be sufficiently directed toward technologies capable of reducing the harmful emissions. A legislative mandate and deadline for reducing acid rain emissions provides the research program with a goal and direction which is totally lacking from the proposals currently before Congress. Linking technology demonstration grants to pollution control standards will, consistent with the philosophy of the 1977 Clean Air Acts, force the development of technologies capable of achieving those standards and provide electric utility researchers and their consultants with a badly needed incentive to succeed.

There are other serious defects in the current proposals for clean coal technology research. First, the program must be reoriented toward research on those technologies which have the greatest potential for application in existing electric generating plants. Plants built before the imposition of new source performance standards under the 1977 Clean Air Act are the primary cause of acid rain in eastern North America. If clean coal technology is supposed to stop acid rain, then research must be focused on developing technologies capable of being retrofitted on these existing plants. The current proposals fail to do so. Instead, DOE would be free to spend much of the funds on design for new plants, which will never be a major source of acid rain control because of stringent emission control requirements already in place for new plants.

Another problem is time: some of the proposals for clean coal technology will simply take too long. Senator Byrd's proposal for a ten-year period of research on emission control technologies requires more time than we in New York can afford. Our lakes and streams are suffering mounting damage every year. Any new emission control methods must be developed in time to be put in place within an eight to ten-year period -- not simply researched for that period of time.

I. INCENTIVE TO SUCCEED

A deadline for emission controls is essential for a successful clean coal technology program for several reasons. As proposed, research funds will be distributed by the United States Department of Energy primarily to electric utilities, coal mining companies or their consultants. These institutions have historically been among the leading opponents of acid rain controls. It is simply unrealistic to expect that their past opposition will be overcome by a no-strings-attached subsidy for the industry's research and development needs.

The industry's primary argument against acid rain control bill is the cost of retrofitting existing "scrubber" control technology onto coal fired power plants.[3] Industry will quickly realize that the more effectively the funds are used to develop less expensive means of control, the sooner the day will come when the emission reduction requirements will be imposed by congressional mandate. The emerging control methods, though somewhat less expensive than currently available scrubber technology, is still quite expensive to install and operate. Given this continuing economic interest in opposing acid rain control legislation, there will be a natural tendency to delay results, direct the funds toward less promising technologies or investigations and generally avoid any firm conclusions about the availability of cheaper control technology.

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[3] The term "scrubber" is short hand for "Flue Gas Desulfurization", a technology which removes sulfur gases emitted from coal combustion by injecting water and alkaline compounds which react with the sulfur gas to form a sludge which is then collected for disposal. Wet scrubbers are widely used and achieve a 90% sulfur gas removal.

For seventeen years under the Clean Air Act, it has been the policy of Congress to force the development of pollution control technology by setting standards and deadlines in advance of, and as an incentive for the industry's research and technology development. Experience teaches us that serious development of pollution control technology does not occur until there is a market for those controls. An impending deadline for pollution reduction creates that market. The present clean coal proposals would reverse this policy. They do not create a market in control devices and only delay the establishment of emission limits until the regulated community comes up with solutions. Proposals to provide direct subsidies to polluting industries to advise the government on how and when they should be regulated is, I believe, absurd and unprecedented in our nation's history. I urge members of the Congress not to support this approach.

A firm emission reduction deadline will be the best insurance that the Department of Energy and the grantees will efficiently use the research funds to produce meaningful results. Senator Mitchell has introduced legislation which links technology research funding to a comprehensive acid rain control bill. Therefore, I urge the committee to adopt the approach contained in Senator Mitchell's Bill (S. 321).

II. OTHER WEAKNESSES IN THE BYRD BILL AND THE ADMINISTRATION PROPOSALS

The record shows that these clean coal proposals were based on earlier programs which have very little to do with acid rain control. The Department of Energy's programs to date have not been focused on technologies to reduce emissions from existing power plants, which are the primary sources of acid rain. Instead, they have primarily been designed to improve markets for coal and to develop control systems for new plants, so that as electricity demand grows, coal will be the fuel of choice in the United States and abroad. The DOE program was not primarily directed at developing new retrofit emission controls for existing coal-fired pollution sources. A study by the Congressional Research Service found that few of the projects which DOE has funded to date have the potential for reducing acid rain pollutants from existing sources.

As a result of domestic and international pressures, there has been an attempt to define this research program as a step toward acid rain controls. Nevertheless, as currently proposed by the administration and Senator Byrd, the revised clean coal technology proposals fail to fully redirect the program toward developing retrofit emission controls for existing sources.

The primary sources of acid rain causing pollutants are older plants constructed before the passage of the Clean Air Act and its strict new source performance standard regulations. The Congressional Research Service recently reported that many utilities will be meeting electric demand for many decades by extending the useful lives of existing power plants.[4] This means that existing facilities will remain the major source of sulfur dioxide emissions from the United States well into the next century. For this reason, it makes no sense in terms of controlling acid rain to devote large amounts of the clean coal research funds to technologies which would only be used in new electric generating plants.

Under the Byrd bill, there would be no limitations on how the funds will be divided between controls for existing plants and controls for new plants.[5] The President's proposal is also so vague that it could be interpreted to support any allocation that DOE chooses to make.[6] Thus, these proposals cannot be considered a new initiative by the United States for acid rain purposes. Rather they merely extend an existing DOE program established primarily for other purposes.

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[4] Parker, L.B., and Kaufman, A., Clean Coal Technology and Acid Rain Control: Birds of A Feather?, Congressional Research Service Report No. 85-207 ENR, October 23, 1985 (hereinafter "CRS Report").

[5] S. 879 authorizes the DOE Secretary to provide financial assistance to commercial sized projects utilizing "innovative clean coal technologies" to encourage their commercial development. This term is broadly defined and not limited to retrofit demonstrations. Section 4(a) of the bill provides criteria for determining when to provide assistance, but is unclear whether a priority is to be placed on retrofit technologies. For example, at several other places in the bill there are references to use of the funds for clean coal technology for a "new facility." Elsewhere the Act refers to equipment to "retrofit, repower and modernize." But "repowering" typically involves such high costs that it would be appropriate for only a small number of existing plants.

[6] In the Administration's April 10, 1987 Amended FY 1988 Budget Request, it is stated that the new funds would be available for demonstration projects to be conducted in

(Footnote Continued)

Thus, while it is essential to link the funds to enactment of an emission reduction deadline, it is also critically important to modify the language of Senator Byrd's bill, the Administration's plan and the various budget proposals to require that most -- if not all -- of the funds will be spent on technologies capable of being retrofitted onto existing electric utility power plants.

The Byrd proposal has another feature which is particularly objectionable to acid rain control proponents. On the mistaken assumption that the United States does not currently have affordable means to reduce acid rain pollutants, Senator Byrd proposes a ten-year research program to develop the needed technology. This would be a waste of time and money. Refined flue gas desulfurization equipment is a readily available and proven technology, and hundreds of these systems have already been

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(Footnote Continued)
accordance with the already established guidelines of the existing Clean Coal Technology Program. Under that Program, only three of nine projects funded were even arguably suitable for retrofit applications and those projects involved only a 6% of the funds granted. See, CRS Report, supra at 26. The Administration's Amended Budget Request makes no mention of retrofit technology at all and only passing reference to air pollution or acid rain. See, Letter, Secretary Herrington to Chairman Sidney Yates, House Subcommittee on Interior and Related Agencies and attached "Department of Energy FY, 1988 Congressional Budget Request Clean Coal Technology, Innovative Control Technology."

installed. Other less expensive technologies are now ready for commercial use, or are very close to marketing, and could be applied to some plants in the near future.

For example, in EPA's proposed New Source Performance Standard for industrial boilers, "spray driers" were described as a demonstrated technology capable of achieving a 90 percent reduction in sulfur dioxide for any quality of coal.[7] The Tennessee Valley Authority is conducting a test at its Shawnee plant in Paducah, Kentucky, to demonstrate the performance and commercial feasibility of a spray dryer sulfur dioxide control system for retrofit applications on high sulfur coal fired utility boilers. The project will be completed in early 1989[8]

Another emerging technology considered appropriate for retrofitting on coal fired plants is known as Lime Stone Injection Multi-stage Burners ("LIMB") or "dry sorbent injection."[9] DOE projects that this system will be available in the early

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[7] A spray drier is a simpler form of scrubber mechanism involving conversion of sulfur dioxide gas into a particle form that is then captured by a conventional bag house or electrostatic precipitator. Spray driers generally have lower capital costs than scrubbers. U.S. Dept. of Energy, Second Report to Congress on Emerging Clean Coal Technologies Capable of Retrofitting, Repowering or Modernizing Existing Facilities, May, 1987, p. 115.

[8] U.S. Department of Energy, "Americas Clean Coal Commitment", February 1987, DOE/FE-0083, Washington, D.C.

[9] Dry sorbent injection involves the injection of dry SO_2 sorbent such as limestone or hydrated lime directly into the combustion zone to capture SO_2.

1990s.[10] EPA, DOE and private companies are co-sponsoring a 115-megawatt demonstration project, with testing to be completed in 1988.[11] Other technologies, including advanced coal cleaning methods,[12] and coal slurry techniques,[13] are also expected to be available in the first half of the next decade.

In the area of NO_x control, both combustion modification (air slagging) and flue gas treatment have already been commercialized.[14]

In the absence of any evidence supporting the need for a 10-year-research program, the Byrd and Reagan Administration proposals should make their research time frames consistent with the major acid rain control bills. Acid rain bills pending in Congress call for achievement of emission reductions within ten years. To meet this goal, research programs must produce technologies that can be installed well in advance of this deadline. A research phase of five to six years is, therefore, much more appropriate.

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[10] Id. at 38.

[11] CRS, Limb report.

[12] Coal cleaning involves separation of ash and sulfur from the fuel before it is burned, usually at the point of mining. Conventional coal cleaning is in wide use. More advanced methods include chemical or biological cleaning processes.

[13] Coal slurry refers to the conversion of solid coal fuel into a liquid - during which sulfur and ash are removed.

[14] D.O.E., Second Report to Congress, supra, page 118.

III. HARMONIZING THE CLEAN COAL RESEARCH WITH ACID RAIN CONTROLS.

The chances of enacting such a large subsidy for industry research and development are slight as long as there is the strong suspicion that a clean coal technology program is intended solely as a means of delaying acid rain controls. It is fair to ask whether taxpayers are being asked to pay for research to develop technology which the clean coal proponents never really intend to implement. None of the emerging technologies are likely to be used until there is a market for them, and the only way to create that market is to require significant emission reductions.[15] It will be difficult for clean coal proponents to rationalize this fact with their continuing opposition to emission reduction bills. Until they are prepared to link clean coal funding to emission reduction deadlines, the result will most likely be a stalemate in which the technology research is not accelerated and acid rain legislation is not passed.

But such a stalemate is unacceptable to almost everyone and is not likely to last. The pressures are building for acid rain control legislation and opponents are increasingly on the defensive. There is also the possibility that a new Administration in 1989 will impose acid rain control requirements under the existing Clean Air Act, or that the federal courts will interpret that law in a way that requires EPA to order emission reductions[16] If the coal and electric utility industries do not obtain research funds soon, they risk deadlines for emission reduction which, as a result of public impatience, will require the industry to begin construction on currently available acid rain control technology.

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[15] CRS Report, supra, at 4, 42-44.

Proponents of clean coal technology must also recognize their proposal is a radical departure from pollution control policies established by Congress in a variety of environmental protection legislation. Much of the legislation passed in the 1970's and the 1980's was based on "technology-forcing" concepts. In other words, standards and pollution reduction deadlines were established with the understanding that if emission control technologies were not yet available, the establishment of the deadline would create a market for and an incentive to develop controls in time for compliance. This approach has been very successful in spurring the development of control technologies, which would otherwise not have been developed.

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[16] In 1983, the U.S. Court of Appeals for the District of Columbia issued a decision under the stack height section of the Clean Air Act (§ 123) which will require modest emission reductions at plants with tall stacks. Sierra Club v. EPA, 719 F.2d 436 (D.C. Cir. 1983) cert denied 468 U.S. 1204 (1984). The next round of that litigation is underway and could force even larger reductions. NRDC v. Thomas, D.C. Docket No. 85-1488 (oral argument scheduled for September 25, 1987). Other cases are pending which could result in court orders to EPA requiring substantial emission reductions under the interstate (§ 126), international (§ 126) and national standards (§§ 108, 109) sections of the Clean Air Act. State of New York v. Thomas, U.S. Supreme Court Docket No. 86-1373 (on petition for writ of certiorari); State of New York v. U.S.E.P.A., D.C. Cir. Docket
(Footnote Continued)

Supporters of environmental controls cannot be expected to depart from this successful formula. Indeed, it is unusual for government to bear such a large burden of the research and development costs which have traditionally been the responsibility of the regulated industry. A break with this tradition must not be made lightly or without assurance that there will be significant environmental benefits.

For these reasons the clean coal research proposals must be modified if they are to gain acceptance from Congress. Parties on both sides of the debate should recognize the practical need to link the research program to a deadline for emission reductions.

IV. RECOMMENDATIONS

In conclusion, I respectfully urge this Committee to re-direct the presently misguided clean coal proposals. The Reagan Administration and Senator Byrd would reward the very industries that are the source of the pollution with generous subsidies from the taxpayers. With no requirement to meet emission reduction goals by specified dates, these industries have no incentive to produce results, in other words, to commercialized new acid rain control technologies in the near

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(Footnote Continued)
No. 84-1055 (argued before the court on December 12, 1985); Environmental Defense Fund v. Thomas, S.D.N.Y. Docket No. 85-9507.

future. To the contrary, by implying that large scale emission reductions are contingent upon successful demonstration of control technology, the present proposals give the DOE and polluting industries every reason, after spending billions, to come up empty-handed and find only that yet more research is required. This is a likely scenario, since a successful demonstration of cost-effective control technology would lead to the very outcome that the industry and its supporters have been vigorously opposing for years, that is, legislation requiring implementation of air pollution emission reductions.

I urge the advocates of clean coal proposals to modify the programs to include amendments to the Clean Air Act that will require significant reductions in annual emissions of sulfur dioxide and nitrogen oxides, and require that any clean coal funding be spent solely on retrofit technologies. Mandated acid rain controls are the only effective way to give regulated industries an incentive to quickly develop efficient and cost-effective technology to meet these emission reduction requirements.

And I urge proponents of comprehensive acid rain control bills to strenuously resist clean coal research proposals as they are currently formulated. The price for clean coal funding must be a mandatory deadline for acid rain reductions. Anything else is a sell-out and a give-away.

Respectfully submitted,

ROBERT ABRAMS

NRECA NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
1800 Massachusetts Avenue, N.W., Washington, D.C. 20036
Telephone: (202) 857-9500

June 2, 1987

J. Bennett Johnston, Chairman
Committee on Energy and Natural Resources
358 Senate Russell Office Building
Constitution Avenue
Washington, D.C. 20510

Dear Bennett:

This letter is being submitted as the comments of the National Rural Electric Cooperative Association (NRECA) on S.879, a bill to encourage commercial development of new clean coal technologies. NRECA represents over 1000 not-for-profit, consumer-owned electric systems located in 46 states and in 2600 of 3141 counties. These systems distribute 7 percent of the nation's electricity to over 25 million people. About 21 percent of cooperatively distributed electricity is purchased from investor-owned utilities (IOUs), and another 50 percent is generated by cooperatively owned power plants. Approximately 80 percent of this self-generated power is from coal-fired units. Our membership's interest and involvement in coal-fired electric generation, therefore, are substantial.

The rural electric cooperatives are also quite familiar with existing clean coal technology. While owning only 6 percent of the nation's total coal-fired generation, cooperatives own and operate about 20 percent of the total flue gas desulfurization (FGD) units in the country. In some cases, these units remove well over 90 percent of the sulfur dioxide (SO_2) from boiler flue gas and operate as well as or better than any FGD units in the world. But this type of SO_2 removal comes with a hefty price tag. FGD units typically consume up to 7 percent of a power plant's electrical output and produce 3-4 pounds of solid waste for every pound of SO_2 removed. FGD technology works, but it is not efficient or environmentally sound considering the creation of large amounts of solid waste. For large commercial coal-fired generating units in the 400-650 megawatt range, FGD remains the only effective power technology for SO_2 removal. NRECA, therefore, sees a strong need to develop new technology and fully supports the principle of clean coal deployment as envisaged in the Clean Coal Technology Development Act of 1987 (CCTDA) (S.879).

NRECA realizes that the development of new commercial technology is too costly and too risky for any single electric utility to undertake. Thus, we support the concept of a federal grant program to aid those electric utilities willing to take the risks associated with commercializing new technology. NRECA is concerned, however, about how the CCTDA would recover the costs of such clean coal projects which are not covered by the federal grant program. The ratemaking provisions which would "promote widespread use" of CCT, appear to lack adequate standards, guidelines and safeguards which will ensure equitable and appropriate allocation of costs among all ratepayers, ensure that consumer funds are well spent, and prevent potentially damaging anticompetitive results.

The ratemaking provisions, unlike the grant provisions of S.879, are not designed to aid a limited number of individually approved projects aimed at providing "the experience necessary at a commercial scale to reduce the technological, financial and regulatory risks." Rather, they provide what may prove to be extraordinarily costly incentives for an undefined number of projects indefinitely. While the grant program is limited to $350 million a year for 10 years, with review of each project by the Secretary of Energy, utilities under the incentive portion of the bill are permitted to build as many new facilities or retrofit as many existing facilities as they choose, all with special incentives which could have a very significant rate impact on ultimate consumers. In the latter case, the Secretary of Energy only designates which technologies receive the special incentives; utilities are then free to construct their own projects and are relieved of the burden of proving that the money was prudently spent.

The bill also has the potential for creating competitive disadvantages for those cooperative and municipal systems which purchase power from investor-owned utilities obtaining the "incentives" provided by the bill. These disadvantages include price squeezes, in which the wholesale rates co-ops pay for bulk power are increased to a level which makes it impossible to compete with their wholesale supplier for retail load. "Double whammies" are also a disadvantage: co-ops pay for building both their own power plants not yet on line and those of their IOU wholesale supplier which they never intend to use. CCTDA will allow IOUs to obtain very significant increases in the rates charged to their cooperative and municipal wholesale customers because their rates are regulated by FERC which will adopt all the proposed rate incentives. The state commissions, on the other hand, may follow normal ratemaking principles even though there are some incentives to encourage their use of the criteria which FERC will adopt. Thus, in many states, the FERC-regulated wholesale rates which co-op and municipal systems pay may include the incentives, while the retail rates paid by consuming customers of the investor-owned utilities would not include these incentives. Such a result would create even more problems for co-ops whose rates are already more than 15 percent higher on a nationwide basis than their neighboring utilities.

An examination of only the provision for amortization of the CCT plants over 5, rather than 20-40, years would result in wholesale rate increases which more closely resemble the inclusion of several new facilities, rather than one. The incentive rate of return suggested in the bill would make the impact on consumers even more adverse; in addition, there is little effective authority to raise serious questions about such factors as management, since there is a presumption of prudency.

Finally, we must express some concern about the possibility that the bill could divert funds from the study, development or commercialization of alternative means of improving the environment through noncoal-related technologies. Even though rural electric cooperatives have a special interest in coal, we are vitally aware of other alternative means of controlling emissions -- including nongeneration options, such as load management and transmission. We therefore recommend that close attention be paid to designing a bill which, while encouraging the cleaner use of coal, will not create a bias against other technologies.

To summarize, NRECA supports the provisions for deployment of clean coal technology contained in S.879 that would enhance commercial development by easing financial and risk impediments associated with building prototype facilities. While NRECA understands the desire to ease regulatory restrictions on passing clean coal technology costs to the electric consumer, we are nonetheless concerned that the regulatory abatements in Section 5 are too broad and place too much of the burden on the ratepayer.

We would like to express our appreciation for the opportunity of presenting our views, and to pledge support for the utilization of the nation's vast coal resources more cleanly and efficiently. We commend the sponsors of the bill for the efforts made in that direction.

Sincerely,

Bob Bergland
Executive Vice President

BB:mcg

STATE OF ILLINOIS
Illinois Commerce Commission

MARY B. BUSHNELL
Chairman

527 East Capitol Avenue
P.O. Box 19280
Springfield, Illinois 62794-9280

June 12, 1987

The Honorable J. Bennet Johnston, Chairman
Senate Committee on Energy and Natural Resources
Attention: Sheryl Moss
312 Hart Building
Washington, D.C. 20510

Re: Senate Bill 879 - Clean Coal Technology Deployment Act

Dear Chairman Johnston:

The Illinois Commerce Commission wishes to express its interest in Senate Bill 879 and present the Committee on Energy and Natural Resources with the Commission's comments in regard to the proposed legislation. The following position statements represent the Commission's concerns and comments in regard to Senate Bill 879:

Illinois Commerce Commission
Position Statements

1) In general, the Commission supports attempts at both the federal and state levels to solve the recognized acid rain problem.

2) In line with National Association of Regulatory Utility Commissioners, the Commission supports the development of clean coal technologies and advocates federal co-sponsorship of such programs, realizing that utilities cannot wholly assume this task.

3) However, in conjunction with statements 1 and 2, the Commission seeks to control the decision making process at the state level in relation to the following specific issues identified in Senate Bill 879:

   - any provision for automatic inclusion of any clean coal project expenditure for design and engineering by a utility as an operating expense.

- any provision for automatic inclusion in the rate base of any clean coal capital cost expenditures.
- the time period allowed for amortization of capital costs (5 years is stated in Senate Bill 879).
- any provision for an incentive rate of return on any clean coal capital cost included in the rate base.
- the inclusion of the rebuttable presumption that any clean coal project expenditure is prudent.

4) State regulators should retain the current right to make decisions related to the above mentioned issues in the context of local conditions.

5) While the Commission supports resolution of the acid rain problem through the use of clean coal technologies, binding the Commission to accept particular combinations of cost and quality associated with this goal could harm substantially the intent of the legislation. Automatic inclusions of shared costs, rebuttable presumptions of prudency, and modifying the rate of return all serve as barriers to protecting ratepayers from bearing the high cost of solving the acid rain problem. Encouraging solutions based on these criteria, rather than criteria designed to minimize cost for a desired outcome, could result in substantial public criticism and ultimate failure of the program. As long as the Commission is preempted from ruling out poor solutions to the problem because of automatic pass-through clauses, the threat of failure caused by attention to higher than necessary costs always exists.

Your Committee's consideration of the Illinois Commission's position statements is appreciated. As Chairman of the Commission, I would be glad to further discuss the provisions in Senate Bill 879 at your convenience. It is my opinion that a successful resolution of the potential problems mentioned above can be accomplished.

Thank you for your attention to this matter.

Sincerely,

Mary B. Bushnell

Mary B. Bushnell
Chairman

MBB/t

cc: Ann McCabe
Julie Kelner
John Plumerfelt

CONSUMER ENERGY COUNCIL of AMERICA
2000 L Street NW Suite 802 Washington DC 20036-202-659-0404

Executive Director
ELLEN BERMAN

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United Steelworkers
of America

JOHN SWEENEY
Int'l President
Service Employees
Int'l Union

June 3, 1987

JUN - 4 1987

The Honorable J. Bennett Johnston, Jr.
United States Senate
136 Hart Senate Office Building
Washington, DC 20510

Dear Senator Johnston:

On behalf of the Consumer Energy Council of America, the oldest public interest energy policy organization in the nation, I am writing to express my concern regarding S. 879, the Clean Coal Technology Deployment Act. The bill looks "clean" on paper, but, if passed in its current form, could be a dirty deal for consumers.

S. 879, as currently written, would provide incentives to investor-owned utilities to compensate them for the "risks" of "innovative" clean coal technology (CCT) commercialization -- without specifying how the Secretary of Energy will define an "innovative" CCT. The bill could thus skew utilities to invest in fully commercial and demonstrated CCTs that are already economically viable at the expense of equally worthy emission reduction plans.

In addition, the bill grants "a rebuttable presumption that any clean coal project expenditure is prudent," thus placing the burden of proof of imprudent spending decisions on consumers rather than on the utility. By working under the presumption that all CCT expenditures are prudent, the bill denies consumers the opportunity to examine the prudency of implementing individual CCT projects. By relaxing current FERC and state regulatory safeguards, the bill makes consumers bear all the risks of poor management.

And finally, the bill leaves unclear what the impacts on electric rates will be as a result of incentives offered under the Act. As investor-owned utilities take advantage of these incentives, they are able to pass the costs on as 100 percent CWIP, or through five year amortization, or as an operating expense to consumers -- the very consumers who are discouraged from rebutting the prudency of individual projects. Such practices could adversely impact wholesale customers, such as public power systems, rural electric cooperatives and large industries, as well as retail consumers.

I urge you to reexamine the language of S. 879 in order to clarify those provisions that are open to interpretation -- interpetations that are not in the best interest of the nation's consumers.

Sincerely,

Ellen B

Ellen Berman
Executive Director

Public Service Commission of the District of Columbia

450 5th Street, N.W.
Washington, D.C. 20001
(202) 626-5100

IN REPLY REFER TO:

June 5, 1987

Honorable J. Bennett Johnston
United States Senator
Washington, D.C. 20510

Re: Bill S.879: Clean Coal

Dear Senator Johnston:

It has recently come to our attention that S.879, a bill proposing the Clean Coal Technology Deployment Act, has been referred to the Senate Committee on Energy and Natural Resources. The District of Columbia Public Service Commission (DCPSC) wishes to call to your attention, as a member of that committee, our views regarding S.879 in particular, as well as the important issue of acid rain and efforts to control pollution resulting from the generation of electricity.

The problem of acid rain is a serious one. It is our view that effective control will not be established unless the problem is confronted directly at the national level. In that regard, the DCPSC is concerned that, although there may be some merit in promoting the development of new clean coal technologies, any legislation instituted to encourage utilities to do so should not be viewed as a substitute for a direct program to control acid rain.

Proven technologies are currently available to reduce the pollution which causes acid rain. Through the use of available technologies such as scrubbers, fluidized bed combustion, and coal cleaning, the Nation's utilities can control the emission of both sulfur dioxide and nitrogen oxides.

Even when viewed on its own merits, apart from the debate over acid rain control, we find S.879 troublesome for several reasons. The bill as proposed establishes a rebuttable presumption to be applied in rate proceedings conducted by the Federal Energy Regulatory Commission (FERC) and state regulatory agencies that any clean coal expenditure is prudent and further directs the FERC to provide an incentive rate of return on any clean coal capital costs included in a utility's rate base. This proposal may result in unjust rate increases.

This erosion of the power of the FERC and the state commissions to fully review an electric utility's expenditures is objectionable. First, an almost direct passthrough of expenses and capital expenditures incurred by electric utilities in developing and implementing clean coal technologies would certainly result in substantial rate increases. Second, the legislative erosion of the FERC's ability to review an electric utility's capital expenditures and research and development costs would intensify the already disturbing trend among utilities of attempting to avoid state regulation through transactions designed to bring the industry's actions under the "protective umbrella" of a wholesale transaction, regulated at the federal level.

Not only does S.879 ask for an unacceptable sacrifice from taxpayers, but it also calls for a contribution from electric ratepayers nationwide.

Sincerely,

Patricia M. Worthy
Chairman

R Hankins Nesbitt

Ruth Hankins-Nesbitt
Commissioner

Wesley H. Long

Wesley H. Long
Commissioner

STATE OF CALIFORNIA
GEORGE DEUKMEJIAN, Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102

July 30, 198

1987 AUG -3 AM 8:48

The Honorable J. Bennett Johnston
Committee on Energy and Natural Resources
Senate Dirksen Office Building
Constitution Avenue, N.E.
Washington, D.C. 20510

Dear Senator Johnston:

Re: Senate Bill 879--Creation of Clean Coal
Technology Deployment Act

The Public Utilities Commission of the State of California ("CPUC") strongly urges that Senate Bill 879, a bill which creates various incentives to encourage the development of clean coal technologies, be amended to delete Section 6(b). This section creates a rebuttable presumption that any clean coal project expenditure incurred by a state-regulated electric utility shall be deemed prudent by state regulatory commissions.

The CPUC is supportive of measures which are designed to encourage the use of cost-effective and environmentally acceptable technologies for electric utilities. At the same time the CPUC is concerned that measures designed to encourage such technologies do not undercut a state regulator's responsibility to assure adequate and reliable service at reasonable rates to intrastate ratepayers. The creation of a rebuttable presumption that all expenditures related to these technologies are prudent is one measure which would seriously undercut this responsibility.

Under current law, the electric utility has the burden of demonstrating that expenditures for which it seeks recovery in rates are in fact prudent. Placing the burden on the utility makes sense where the utility is in possession of all of the data supporting these expenditures, and is directly knowledgeable of the circumstances under which the expenditures were incurred. A rebuttable presumption of prudency would shift the burden to the state regulator to establish imprudency. The state regulator, however, does not stand in the same position as the utility in terms of access to relevant data and the availability of resources to evaluate the data. Thus, as a practical matter, the state regulator will, in nearly all cases, be compelled to deem utility expenditures prudent. The utility's ratepayers will therefore likely pay higher rates than they otherwise might under existing prudency standards.

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Page 2

While it may be argued that the revision of existing prudency standards applies only to technologies which qualify for regulatory incentives under the Clean Coal Technology Deployment Act, the CPUC is greatly concerned that such revision will establish a precedent for other technologies. Accordingly, the CPUC opposes any revision to existing prudency standards in order to meaningfully carry out its statutory responsibility to protect California ratepayers.

Your attention to this important matter is greatly appreciated. Please feel free to contact me if you have any questions.

Sincerely,

Stanley Hulett

Stanley Hulett
President